⊕EPA

SUPPLEMENT E

TO

COMPILATION
OF
AIR POLLUTANT
EMISSION FACTORS

VOLUME I:

STATIONARY POINT
AND AREA SOURCES

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INSTRUCTIONS FOR INSERTING

SUPPLEMENT E OF VOLUME I

INTO AP-42

Pp. iii and iv replace same. New Publications In Series.

Pp. v through viii replace same. New Contents.

Pp. ix through xvi replace same. New Key Word Index.

Pp. 1.2-1 through 10 (blank) replace 1.2-1 through 8. Major Revision.

Pp. 1.4-1 through 8 (blank) replace 1.4-1 through 6. Major Revision.

Pp. 1.5-1 through 4 replace same. Major Revision.

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Pp. 1.9-1 through 6 (blank) replace 1.9-1 through 4. Major Revision.

Pp. 1.10-1 through 12 replace 1.10-1 through 6. Major Revision.

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Pp. 3.3-1 through 8 (blank) replace 3.3-1 and 2. Major Revision.

Pp. 3.4-1 through 10 (blank) replace 3.4-1 and 2. Major Revision.

Delete Section 4.3, "Storage Of Organic Liquids". Replaced by new Chapter 12.

Pp. 5.15-3 and 4 replace same. Editorial change.

Add pp. 12-1 through 124. New Chapter.

PUBLICATIONS IN SERIES

PUBLICATIONS IN SERIES (Cont.)

CONTENTS

KEY WORD INDEX

1.2 ANTHRACITE COAL COMBUSTION

1.2.1 General[1-4]

Anthracite coal is a high-rank coal with more fixed carbon and less volatile matter than either bituminous coal or lignite; anthracite also has higher ignition and ash fusion temperatures. In the United States, nearly all anthracite is mined in northeastern Pennsylvania and consumed in Pennsylvania and its surrounding states. The largest use of anthracite is for space heating. Lesser amounts are employed for steam/electric production; coke manufacturing, sintering and pelletizing; and other industrial uses. Anthracite currently is only a small fraction of the total quantity of coal combusted in the United States.

Another form of anthracite coal burned in boilers is anthracite refuse, commonly known as culm. Culm was produced as breaker reject material from the mining/sizing of anthracite coal and was typically dumped by miners on the ground near operating mines. It is estimated that there are over 15 million Mg (16 million tons) of culm scattered in piles throughout northeastern Pennsylvania. The heating value of culm is typically in the 1,400 to 2,800 kcal/kg (2,500 to 5,000 Btu/lb) range, compared to 6,700 to 7,800 kcal/kg (12,000 to 14,000 Btu/lb) for anthracite coal.

1.2.2 Firing Practices[5-7]

Due to its low volatile matter content, and non-clinkering characteristics, anthracite coal is largely used in medium-sized industrial and institutional stoker boilers equipped with stationary or traveling grates. Anthracite coal is not used in spreader stokers because of its low volatile matter content and relatively high ignition temperature. This fuel may also be burned in pulverized coal-fired (PC-fired) units, but due to ignition difficulties, this practice is limited to only a few plants in eastern Pennsylvania. Anthracite coal has also been widely used in hand-fired furnaces. Culm has been combusted primarily in fluidized bed combustion (FBC) boilers because of its high ash content and low heating value.

Combustion of anthracite coal on a traveling grate is characterized by a coal bed of 8 to 13 cm (3 to 5 inches) in depth and a high blast of underfire air at the rear or dumping end of the grate. This high blast of air lifts incandescent fuel particles and combustion gases from the grate and reflects the particles against a long rear arch over the grate towards the front of the fuel bed where fresh or "green" fuel enters. This special furnace arch design is required to assist in the ignition of the green fuel.

A second type of stoker boiler used to burn anthracite coal is the underfeed stoker. Various types of underfeed stokers are used in industrial boiler applications but the most common for anthracite coal firing is the single-retort side-dump stoker with stationary grates. In this unit, coal is fed intermittently to the fuel bed by a ram. In very small units the coal is fed continuously by a screw. Feed coal is pushed through the retort and upward towards the tuyere blocks. Air is supplied through the tuyere blocks on each side of the retort and through openings in the side grates. Overfire air is commonly used with underfeed stokers to provide combustion air and turbulence in the flame zone directly above the active fuel bed.

In PC-fired boilers, the fuel is pulverized to the consistency of powder and pneumatically injected through burners into the furnace. Injected coal particles burn in suspension within the furnace region of the boiler. Hot flue gases rise from the furnace and provide heat exchange with boiler tubes in the walls and upper regions of the boiler. In general, PC-fired boilers operate either in a wet-bottom or dry bottom mode; because of its high ash fusion temperature, anthracite coal is burned in

dry-bottom furnaces.

For anthracite culm, combustion in conventional boiler systems is difficult due to the fuel's high ash content, high moisture content, and low heating value. However, the burning of culm in a fluidized bed system was demonstrated at a steam generation plant in Pennsylvania. A fluidized bed consists of inert particles (e.g., rock and ash) through which air is blown so that the bed behaves as a fluid. Anthracite coal enters in the space above the bed and burns in the bed. Fluidized beds can handle fuels with moisture contents up to near 70 percent (total basis) because of the large thermal mass represented by the hot inert bed particles. Fluidized beds can also handle fuels with ash contents as high as 75 percent. Heat released by combustion is transferred to in-bed steam-generating tubes. Limestone may be added to the bed to capture sulfur dioxide formed by combustion of fuel sulfur.

1.2.3 Emissions And Controls[4-6]

Particulate matter (PM) emissions from anthracite coal combustion are a function of furnace firing configuration, firing practices (boiler load, quantity and location of underfire air, soot blowing, flyash reinjection, etc.), and the ash content of the coal. Pulverized coal-fired boilers emit the highest quantity of PM per unit of fuel because they fire the anthracite in suspension, which results in a high percentage of ash carryover into exhaust gases. Traveling grate stokers and hand fired units produce less PM per unit of fuel fired, and coarser particulates, because combustion takes place in a quiescent fuel bed without significant ash carryover into the exhaust gases. In general, PM emissions from traveling grate stokers will increase during soot blowing and flyash reinjection and with higher fuel bed underfeed air flowrates. Smoke production during combustion is rarely a problem, because of anthracite's low volatile matter content.

Limited data are available on the emission of gaseous pollutants from anthracite combustion. It is assumed, based on bituminous coal combustion data, that a large fraction of the fuel sulfur is emitted as sulfur oxides. Also, because combustion equipment, excess air rates, combustion temperatures, etc., are similar between anthracite and bituminous coal combustion, nitrogen oxide emissions are also assumed to be similar. Nitrogen oxide emissions from FBC units burning culm are typically lower than from other anthracite coal-burning boilers due to the lower operating temperatures which characterize FBC beds.

Carbon monoxide and total organic compound emissions are dependent on combustion efficiency. Generally their emission rates, defined as mass of emissions per unit of heat input, decrease with increasing boiler size. Organic compound emissions are expected to be lower for pulverized coal units and higher for underfeed and overfeed stokers due to relative combustion efficiency levels.

Controls on anthracite emissions mainly have been applied to PM. The most efficient particulate controls, fabric filters, scrubbers, and electrostatic precipitators, have been installed on large pulverized anthracite-fired boilers. Fabric filters can achieve collection efficiencies exceeding 99 percent. Electrostatic precipitators typically are only 90 to 97 percent efficient, because of the characteristic high resistivity of low sulfur anthracite fly ash. It is reported that higher efficiencies can be achieved using larger precipitators and flue gas conditioning. Mechanical collectors are frequently employed upstream from these devices for large particle removal.

Older traveling grate stokers are often uncontrolled. Indeed, particulate control has often been considered unnecessary, because of anthracite's low smoking tendencies and the fact that a significant fraction of large size flyash from stokers is readily collected in flyash hoppers as well as in the breeching and base of the stack. Cyclone collectors have been employed on traveling grate stokers,

and limited information suggests these devices may be up to 75 percent efficient on particulate. Flyash reinjection, frequently used in traveling grate stokers to enhance fuel use efficiency, tends to increase PM emissions per unit of fuel combusted. High-energy venturi scrubbers can generally achieve PM collection efficiencies of 90 percent or greater.

Emission factors and ratings for pollutants from anthracite coal combustion and anthracite culm combustion are given in Tables 1.2-1 through 1.2-7. Cumulative size distribution data and size specific emission factors and ratings for particulate emissions are summarized in Table 1.2-8. Uncontrolled and controlled size specific emission factors are presented in Figure 1.2-1. Particle size distribution data for bituminous coal combustion may be used for uncontrolled emissions from pulverized anthracite-fired furnaces, and data for anthracite-fired traveling grate stokers may be used for hand fired units.

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2.   Air Pollutant Emission Factors, APTD-0923, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, April 1970.

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6.   Steam: Its Generation and Use, Thirty-Seventh Edition, The Babcock & Wilcox Company, New York, New York, 1963.

7.   Draft report. Emission Factor Documentation for AP-42 Section 1.2--Anthracite Coal Combustion, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1992.

8.   Inhalable Particulate Source Category Report for External Combustion Sources, EPA Contract No. 68-02-3156, Acurex Corporation, Mountain View, California, January 1985.

TABLE 1.2-1. EMISSION FACTORS FOR SPECIATED METALS FROM ANTHRACITE COAL COMBUSTION IN STOKER FIRED BOILERS[7]
(Emission Factor Rating: E)

Pollutant	Emission factor range lb/ton	Emission factor range kg/Mg	Average emission factor lb/ton	Average emission factor kg/mg
Mercury	8.7E-05 - 1.3E-04	4.4E-05 - 6.5E-05	1.29E-04	6.45E-05
Arsenic	BDL - 2.4E-04	BDL - 1.2E-04	1.85E-04	9.25E-05
Antimony	BDL		BDL	BDL
Beryllium	3.0E-05 - 5.4E-04	1.5E-05 - 2.7E-04	3.07E-04	1.54E-04
Cadmium	4.5E-05 - 1.1E-04	2.3E-05 - 5.5E-05	7.10E-05	3.55E-05
Chromium	5.9E-03 - 4.9E-02	3.0E-03 - 2.5E-02	2.76E-02	1.38E-02
Manganese	9.8E-04 - 5.3E-03	4.9E-04 - 2.7E-03	3.56E-03	1.78E-03
Nickel	7.8E-03 - 3.5E-02	3.9E-03 - 1.8E-02	2.56E-02	1.28E-02
Selenium	4.7E-04 - 2.1E-03	2.4E-04 - 1.1E-03	1.26E-03	6.30E-04

BDL = Below detection limit.

TABLE 1.2-2. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC) AND METHANE (CH_4) FROM ANTHRACITE COAL COMBUSTORS[1]

Source category	TOC			CH_4		
	Average emission factor lb/ton	Average emission factor kg/Mg	Rating	Average emission factor lb/ton	Average emission factor kg/Mg	Rating
Stoker fired boilers	0.20	0.10	E	NA	NA	-
Residential space heaters	NA	NA	-	8	4	E

NA = Data not available.

TABLE 1.2-3. (ENGLISH UNITS) EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM ANTHRACITE COAL COMBUSTORS[7]
(Emission Factor Rating: E)

Pollutant	Stoker fired boilers Emission factor lb/ton	Residential space heaters	
		Emission factor range lb/ton	Average emission factor lb/ton
Biphenyl	2.5E-02	-	-
Phenanthrene	6.8E-03	9.1E-02- 0.43E-01	3.63
Naphthalene	1.3E-01	9.0E-03- 0.0482	3.27
Acenaphthene	NA	1.4E-02- 6.75E-01	0.43
Acenaphthalene	NA	1.4E-02- 3.04E-01	1.46
Fluorene	NA	9.0E-03- 5.78E-02	0.38
Anthracene	NA	9.0E-03- 4.5E-02	0.38
Fluoranthrene	NA	9.6E-02- 3.3E-01	4.86
Pyrene	NA	5.4E-02- 2.4E-01	1.83
Benzo(a)anthracene	NA	1.4E-02 - 2.0E-01	1.15
Chrysene	NA	2.3E-02 - 2.2E-01	2.62
Benzo(k)fluoranthrene	NA	1.4E-02- 6.27E-02	0.37
Benzo(e)pyrene	NA	4.5E-03- 1.45E-02	0.09
Benzo(a)pyrene	NA	3.8E-03 - 9.0E-03	0.06
Perylene	NA	7.6E-04- 2.3E-03	1.4E-02
Indeno(123-cd) perylene	NA	4.5E-03- 1.4E-02	0.10
Benzo(g,h,i,) perylene	NA	4.34E-03- 1.2E-02	0.08
Anthanthrene	NA	1.9E-04- 1.1E-03	6.2E-03
Coronene	NA	1.1E-03- 8.0E-03	0.06

NA = Data not available.

TABLE 1.2-4 (METRIC UNITS) EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM ANTHRACITE COAL COMBUSTORS[7]
(Emission Factor Rating: E)

Pollutant	Stoker fired boilers	Residential space heaters	
	Emission factor kg/Mg	Emission factor range kg/Mg	Average emission factor kg/Mg
Biphenyl	1.25E-02	-	-
Phenanthrene	3.4E-03	4.6E-02- 2.1E-02	3.63
Naphthalene	0.65E-01	4.5E-03 - 0.0241	3.27
Acenaphthene	NA	7.0E-03- 3.38E-01	0.43
Acenaphthalene	NA	7.0E-03- 1.98E-02	1.46
Fluorene	NA	4.5E-03- 2.89E-02	0.38
Anthracene	NA	4.5E-03- 2.3E-02	0.38
Fluoranthrene	NA	4.8E-02- 1.7E-01	4.86
Pyrene	NA	2.7E-02- 1.2E-01	1.83
Benzo(a)anthracene	NA	7.0E-03 - 1.0E-01	1.15
Chrysene	NA	1.2E-02 - 1.1E-01	2.62
Benzo(k)fluoranthrene	NA	7.0E-03- 3.14E-02	0.37
Benzo(e)pyrene	NA	2.3E-03- 7.25E-03	0.09
Benzo(a)pyrene	NA	1.9E-03 - 4.5E-03	0.06
Perylene	NA	3.8E-04- 1.2E-03	1.4E-02
Indeno(123-cd) perylene	NA	2.3E-03- 7.0E-03	0.10
Benzo(g,h,i,) perylene	NA	2.17E-03- 6.0E-03	0.08
Anthanthrene	NA	9.5E-05- 5.5E-04	6.2E-03
Coronene	NA	5.5E-04- 4.0E-03	0.06

NA = Data not available.

TABLE 1.2-5. EMISSION FACTORS FOR PARTICULATE MATTER (PM), AND LEAD (Pb) FROM ANTHRACITE COAL COMBUSTORS[7]

Source Category	PM-Filterable			PM-Condensible			Pb		
	Emission Factor			Emission Factor			Emission Factor		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Stoker fired boilers	$0.9A^a$	$0.45A^a$	C	0.08A	0.04A	C	8.9E-03	4.5E-03	E
Hand fired units	10	5	B	NA	NA	-	NA	NA	-

a. A = ash content of fuel, weight percent.
NA = Data not available.

TABLE 1.2-6. EMISSION FACTORS FOR NITROGEN OXIDE COMPOUNDS (NO_X) AND SULFUR DIOXIDE (SO_2) FROM ANTHRACITE COAL COMBUSTORS[7]

Source category	NO_X			SO_2		
	Emission Factor			Emission Factor		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Stoker fired boilers	9.2	4.6	C	$39S^a$	$19.5S^a$	B
FBC boilers[b]	1.8	0.9	E	2.9	1.5	E
Pulverized coal boilers	18	9	B	$39S^a$	$19.5S^a$	B
Residential space heaters	3	1.5	B	$39S^a$	$19.5S^a$	B

a. S = weight percent sulfur.
b. FBC = Fluidized bed combustion; FBC boilers burning culm fuel; all other sources burning anthracite coal.

External Combustion Sources

TABLE 1.2-7. EMISSION FACTORS FOR CARBON MONOXIDE (CO) AND CARBON DIOXIDE (CO_2) FROM ANTHRACITE COAL COMBUSTORS[7]

Source category	CO Emission Factor			CO_2 Emission Factor		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Stoker fired boilers	0.6	0.3	B	5680	2840	C
FBC boilers[a]	0.3	0.15	E	NA	NA	-

NA = Data Not Available

a. FBC = Fluidized bed combustion; FBC boilers burning culm fuel; all other sources burning anthracite coal.

TABLE 1.2-8. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED ANTHRACITE COAL[8]
(Emission Factor Rating: D)

Particle size[c] (µm)	Cumulative mass % ≤ stated size			Cumulative emission factor[a] kg/Mg (lb/ton) coal, as fired		
	Uncontrolled	Controlled[b]		Uncontrolled	Controlled[b]	
		Multiple cyclone	Baghouse		Multiple cyclone	Baghouse
15	32	63	79	1.6A (3.2A)	0.63A (1.26A)	0.0079A (0.016A)
10	23	55	67	1.2A (2.3A)	0.55A (1.10A)	0.0067A (0.013A)
6	17	46	51	0.9A (1.7A)	0.46A (0.92A)	0.0051A (0.010A)
2.5	6	24	32	0.3A (0.6A)	0.24A (0.48A)	0.0032A (0.006A)
1.25	2	13	21	0.1A (0.2A)	0.13A (0.26A)	0.0021A (0.004A)
1.00	2	10	18	0.1A (0.2A)	0.10A (0.20A)	0.0018A (0.004A)
0.625	1	7		0.05A (0.1A)	0.07A (0.14A)	d
TOTAL	100	100	100	5A (10A)	1A (2A)	0.01A (0.02A)

a. A = coal ash weight %, as fired.
b. Estimated control efficiency for multiple cyclone, 80%; baghouse, 99.8%.
c. Expressed as aerodynamic equivalent diameter.
d. Insufficient data.
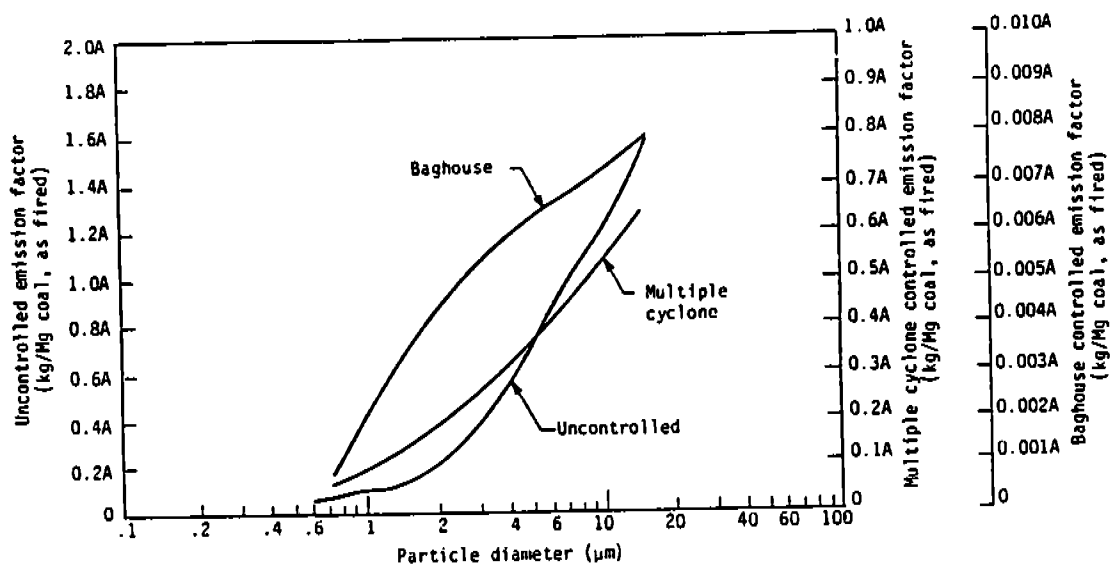
Figure 1.2-1. Cumulative size specific emission factors for dry bottom
boilers burning pulverized anthracite coal.

External Combustion Sources

1.4 NATURAL GAS COMBUSTION

1.4.1 General[1-2]

Natural gas is one of the major fuels used throughout the country. It is used mainly for industrial process steam and heat production; for residential and commercial space heating; and for electric power generation. Natural gas consists of a high percentage of methane (generally above 80 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). Gas processing plants are required for the recovery of liquefiable constituents and removal of hydrogen sulfide before the gas is used (see Natural Gas Processing, Section 9.2). The average gross heating value of natural gas is approximately 8900 kilocalories per standard cubic meter (1000 British thermal units per standard cubic foot), usually varying from 8000 to 9800 kcal/scm (900 to 1100 Btu/scf).

1.4.2 Emissions and Controls[3-5]

Even though natural gas is considered to be a relatively clean-burning fuel, some emissions can result from combustion. For example, improper operating conditions, including poor air/fuel mixing, insufficient air, etc., may cause large amounts of smoke, carbon monoxide (CO), and organic compound emissions. Moreover, because a sulfur-containing mercaptan is added to natural gas to permit leak detection, small amounts of sulfur oxides will be produced in the combustion process.

Nitrogen oxides (NO_x) are the major pollutants of concern when burning natural gas. Nitrogen oxide emissions depend primarily on the peak temperature within the combustion chamber as well as the furnace-zone oxygen concentration, nitrogen concentration, and time of exposure at peak temperatures. Emission levels vary considerably with the type and size of combustor and with operating conditions (particularly combustion air temperature, load, and excess air level in boilers).

Currently, the two most prevalent NO_x control techniques being applied to natural gas-fired boilers (which result in characteristic changes in emission rates) are low NO_x burners and flue gas recirculation. Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses NO_x formation. The three most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners, staged fuel burners, and radiant fiber burners. Nitrogen oxide emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners. Other combustion staging techniques which have been applied to natural gas-fired boilers include low excess air, reduced air preheat, and staged combustion (e.g., burners-out-of-service and overfire air). The degree of staging is a key operating parameter influencing NO_x emission rates for these systems.

In a flue gas recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the gas is mixed with combustion air prior to being fed to the burner. The FGR system reduces NO_x emissions by two mechanisms. The recycled flue gas in made up of combustion products which act as inerts during combustion of the fuel/air mixture. This additional mass is heated in the combustion zone, thereby lowering the peak flame temperature and reducing the amount of NO_x formed. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of flue gas recirculated is a key operating parameter influencing NO_x emission rates for these systems. Flue gas recirculation is

normally used in combination with low NO_x burners. When used in combination, these techniques are capable of reducing uncontrolled NO_x emissions by 60 to 90 percent.

Two post-combustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions by further amounts are selective noncatalytic reduction and selective catalytic reduction. These systems inject ammonia (or urea) into combustion flue gases to reduce inlet NO_x emission rates by 40 to 70 percent.

Although not measured, all particulate matter (PM) from natural gas combustion has been estimated to be less than 1 micrometer in size. Particulate matter is composed of filterable and condensible fractions, based on the EPA sampling method. Filterable and condensible emission rates are of the same order of magnitude for boilers; for residential furnaces, most of the PM is in the form of condensible material.

The rates of CO and trace organic emissions from boilers and furnaces depend on the efficiency of natural gas combustion. These emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. In some cases, the addition of NO_x control systems such as FGR and low NO_x burners reduces combustion efficiency (due to lower combustion temperatures), resulting in higher CO and organic emissions relative to uncontrolled boilers.

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1 through 1.4-3. For the purposes of developing emission factors, natural gas combustors have been organized into four general categories: utility/large industrial boilers, small industrial boilers, commercial boilers, and residential furnaces. Boilers and furnaces within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas. The primary factor used to demarcate the individual combustor categories is heat input.
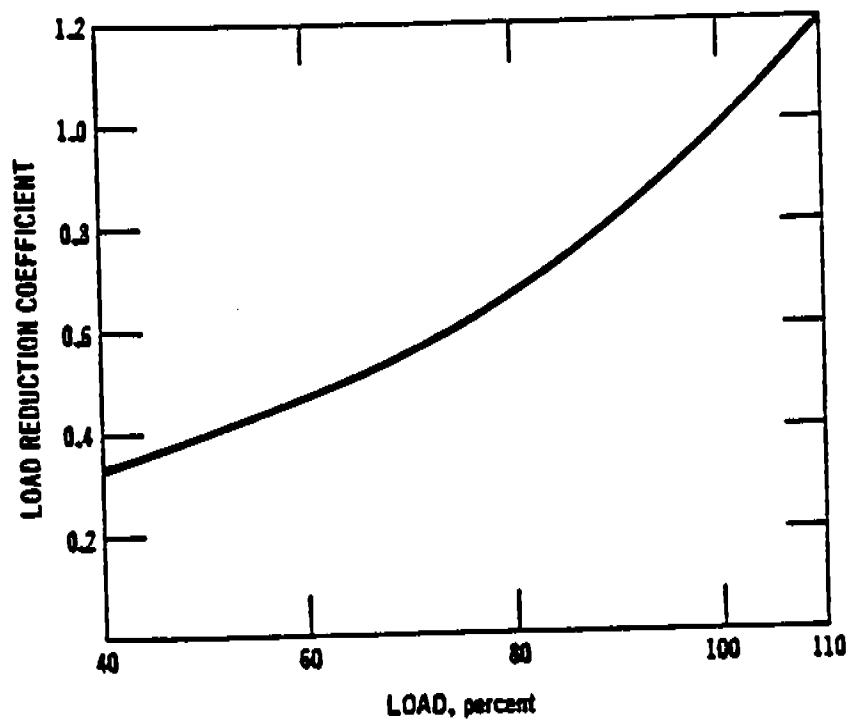
Figure 1.4-1. Load reduction coefficient as function of boiler load.
(Used to determine NO_x reductions at recduced loads in large boilers).

External Combustion Sources

TABLE 1.4-1. EMISSION FACTORS FOR PARTICULATE MATTER (PM) FROM NATURAL GAS COMBUSTION[6,a,b]

Combustor type (size, 10^6 Btu/hr heat input)	Filterable PM[c]			Condensible PM[d]		
	kg/10^6 m^3	lb/10^6 ft^3	Rating	kg/10^6 m^3	lb/10^6 ft^3	Rating
Utility/large industrial boilers (>100)						
Uncontrolled	16-80	1-5	B	NA	NA	
Small industrial boilers (10 - 100)						
Uncontrolled	99	6.2	B	120	7.5	D
Commercial boilers (0.3 -<10)						
Uncontrolled	72	4.5	C	120	7.5	C
Residential furnaces (<0.3)						
Uncontrolled	2.8	0.18	C	180	11	D

NA = not applicable

a. Expressed as weight pollutant/volume natural gas fired.
b. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.
c. Filterable PM is that particulate matter collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
d. Condensible PM is that particulate matter collected in the impinger portion of an EPA Method 5 (or equivalent) sampling train.

TABLE 1.4-2. EMISSION FACTORS FOR SULFUR DIOXIDE (SO_2), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[6,a,b]

Combustor Type (size, 10^6 Btu/hr heat input)	SO_2[c]			NO_x[d]			CO		
	kg/10^6m^3	lb/10^6ft^3	Rating	kg/10^6m^3	lb/10^6ft^3	Rating	kg/10^6m^3	lb/10^6ft^3	Rating
Utility/large industrial boilers (>100)									
Uncontrolled	9.6	0.6	A	8800	550[f]	A	640	40	A
Controlled - Low NO$_x$ burners	9.6	0.6	A	1300	81	D[e]	NA	NA	NA
Controlled - Flue gas recirculation	9.6	0.6	A	850	53	D[e]	NA	NA	NA
Small industrial boilers (10-100)									
Uncontrolled	9.6	0.6	A	2240	140	A	560	35	A
Controlled - Low NO$_x$ burners	9.6	0.6	A	1300	81	D[e]	980	61	D
Controlled - Flue gas recirculation	9.6	0.6	A	480	30	C	590	37	C
Commercial boilers (0.3-<10)									
Uncontrolled	9.6	0.6	A	1600	100	B	330	21	C
Controlled - Low NO$_x$ burners	9.6	0.6	A	270	17	C	425	27	C
Controlled - Flue gas recirculation	9.6	0.6	A	580	36	D	NA	NA	NA
Residential Furnaces (<0.3)									
Uncontrolled	9.6	0.6	A	1500	94	B	640	40	B

NA = Not Applicable.

a. Expressed as weight pollutant/volume natural gas fired.

b. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

c. Reference 7. Based on average sulfur content of natural gas, 4600 g/10^6 Nm^3 (2000 gr/10^6 scf).

d. Expressed as NO$_2$. For tangentially fired units, use 4400 kg/10^6 m^3 (275 lb/10^6 ft^3). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. Note that NO$_x$ emissions from controlled boilers will be reduced at load conditions.

e. Emission factors apply to packaged boilers only.

TABLE 1.4-3. EMISSION FACTORS FOR CARBON DIOXIDE (CO_2), AND TOTAL ORGANIC COMPOUNDS (TOC) FROM NATURAL GAS COMBUSTION[6,a]

Combustor Type (size, 10^6 Btu/hr heat input)	CO_2^c			TOC		
	$kg/10^6m^3$	$lb/10^6ft^3$	Rating	$kg/10^6m^3$	$lb/10^6ft^3$	Rating
Utility/large industrial boilers (>100)						
Uncontrolled	NA	NA		28[b]	1.7[b]	C
Small industrial boilers (10-100)						
Uncontrolled	1.9E06	1.2E05	D	92[c]	5.8[c]	C
Commercial boilers (0.3-<10)						
Uncontrolled	1.9E06	1.2E05	C	92[d]	5.8[d]	C
Uncontrolled	2.0E06	1.3E05	D	180[d]	11[d]	D

NA = Not Applicable.

a. Expressed as weight pollutant/volume natural gas fired. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values bay multiplying the given factor by the ratio of the specified heating value to this average heating value.

b. Reference 8: methane comprises 17 percent of organic compounds.

c. Reference 8: methane comprises 52 percent of organic compounds.

d. Reference 8: methane comprises 34 percent of organic compounds.

References for Section 1.4

1. Exhaust Gases From Combustion and Industrial Processes, EPA Contract No. EHSD 71-36, Engineering Science, Inc., Washington, D.C., October 1971.

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3. Background Information Document For Industrial Boilers, EPA-450/3-82-006a, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, March 1982.

4. Background Information Document For Small Steam Generating Units, EPA-450/3-87-000, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, 1987.

5. Fine Particulate Emissions From Stationary and Miscellaneous Sources in the South Coast Air Basin, California Air Resources Board Contract No. A6-191-30, KVB, Inc., Tustin, California, February 1979.

6. Draft report. Emission Factor Documentation for AP-42 Section 1.4--Natural Gas Combustion, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, September 1992.

7. Systematic Field Study of NO_x Emission Control Methods For Utility Boilers, APTD-1163, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, December 1971.

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1.5 LIQUIFIED PETROLEUM GAS COMBUSTION

1.5.1 General[1]

Liquified petroleum gas (LPG) consists of butane, propane, or a mixture of the two, and of trace amounts of propylene and butylene. This gas, obtained from oil or gas wells as a gasoline refining byproduct, is sold as a liquid in metal cylinders under pressure and, therefore, is often called bottled gas. Liquified petroleum gas is graded according to maximum vapor pressure, with Grade A being mostly butane, Grade F mostly propane, and Grades B through E being varying mixtures of butane and propane. The heating value of LPG ranges from 6,480 kcal/liter (102,000 Btu/gallon) for Grade A to 6,030 kcal/liter (91,000 Btu/gallon) for Grade F. The largest market for LPG is the domestic/commercial market, followed by the chemical industry and internal combustion engines.

1.5.2 Emissions and Controls[1-4]

Liquified petroleum gas is considered a "clean" fuel because it does not produce visible emissions. However, gaseous pollutants such as carbon monoxide (CO), organic compounds, and nitrogen oxides (NO_x) do occur. The most significant factors affecting these emissions are burner design, burner adjustment, and flue gas venting. Improper design, blocking and clogging of the flue vent, and insufficient combustion air result in improper combustion and the emissions of aldehydes, CO, hydrocarbons, and other organics. Nitrogen oxide emissions are a function of a number of variables, including temperature, excess air, fuel/air mixing, and residence time in the combustion zone. The amount of sulfur dioxide (SO_2) emitted is directly proportional to the amount of sulfur in the fuel. Emission factors for LPG combustion are presented in Tables 1.5-1 and 1.5-2.

Nitrogen oxides are the only pollutant for which emission controls have been developed. Propane and butane are being used in Southern California as backup fuel to natural gas, replacing distillate oil in this role pursuant to the phaseout of fuel oil in that region. Emission control for NO_x have been developed for firetube and watertube boilers firing propane or butane. Vendors are now warranting retrofit systems to levels as low as 30 to 40 ppm (based on 3 percent oxygen). These low-NO_x systems use a combination of low NO_x burners and flue gas recirculation. Some burner vendors use water or steam injection into the flame zone for NO_x reduction. This is a trimming technique which may be necessary during backup fuel periods because LPG typically has a higher NO_x-forming potential than natural gas; conventional natural gas emission control systems may not be sufficient to reduce LPG emissions to mandated levels. Also, LPG burners are more prone to sooting under the modified combustion conditions required for low NO_x emissions. The extent of allowable combustion modifications for LPG may be more limited than for natural gas.

One NO_x control system that has been demonstrated on small commercial boilers is flue gas recirculation (FGR). Nitrogen oxide emissions from propane combustion can be reduced by as much as 50 percent by recirculating 16 percent of the flue gas. Nitrogen oxide emission reductions of over 60 percent have been achieved with FGR and low NO_x burners used in combination.

TABLE 1.5-1. (ENGLISH UNITS) EMISSION FACTORS FOR LPG COMBUSTION[a,b]
(Emission Factor Rating: E)

Pollutant	Butane Emission Factor lb/1000 gal		Propane Emission Factor lb/1000 gal	
	Industrial Boilers[c]	Commercial Boilers[d]	Industrial Boilers[c]	Commercial Boilers[d]
Filterable particulate matter[e]	0.6	0.5	0.6	0.4
Sulfur oxides[f]	0.09s	0.09s	0.10s	0.10s
Nitrogen oxides[g]	21	15	19	14
Carbon dioxide	14,700	14,700	12,500	12,500
Carbon monoxide	3.6	2.1	3.2	1.9
Total organic compounds	0.6	0.6	0.5	0.5

a.   Assumes emissions (except SO_x and NO_x) are the same, on a heat input basis, as for natural gas combustion. The NO_x emission factors have been multiplied by a correction factor of 1.5 which is the approximate ratio of propane/butane NO_x emissions to natural gas NO_x emissions.

b.   SCC Codes 102101001, and 10301001 for industrial and commercial/institutional butane combustion. SCC Codes 10201002, and 10301002 for industrial and commercial/institutional propane combustion. SCC Codes 10500110, and 10500210 for industrial and commercial/institutional LPG combustion.

c.   Heat input capacities generally between 10 and 100 million Btu/hour.

d.   Heat input capacities generally between 0.3 and 10 million Btu/hour.

e.   Filterable particulate matter (PM) is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

f.   Expressed as SO_2. S equals the sulfur content expressed on gr/100 ft^3 gas vapor. For example, if the butane sulfur content is 0.18 gr/100 ft^3 emission factor would be (0.09 x 0.18=) 0.016 lb of SO_2/1000 gal butane burned.

g.   Expressed as NO_2.

TABLE 1.5-2. (METRIC UNITS) EMISSION FACTORS FOR LPG COMBUSTION[a,b]
(Emission Factor Rating: E)

Pollutant	Butane Emission Factor kg/1000 liters		Propane Emission Factor kg/1000 liters	
	Industrial Boilers[c]	Commercial Boilers[d]	Industrial Boilers[c]	Commercial Boilers[d]
Filterable particulate matter[e]	0.07	0.06	0.07	0.05
Sulfur oxides[f]	0.011s	0.011s	0.012s	0.012s
Nitrogen oxides[g]	2.5	1.8	2.3	1.7
Carbon dioxide	1,760	1,760	1,500	1,500
Carbon monoxide	0.4	0.3	0.4	0.2
Total organic compounds	0.07	0.07	0.06	0.06

a. Assumes emissions (except SO_x and NO_x) are the same, on a heat input basis, as for natural gas combustion. The NO_x emission factors have been multiplied by a correction factor of 1.5 which is the approximate ratio of propane/butane NO_x emissions to natural gas NO_x emissions.

b. SCC Codes 102101001, and 10301001 for industrial and commercial/institutional butane combustion. SCC Codes 10201002, and 10301002 for industrial and commercial/institutional propane combustion. SCC Codes 10500110, and 10500210 for industrial and commercial/institutional LPG combustion.

c. Heat input capacities generally between 3 and 29 MW.

d. Heat input capacities generally between 0.1 and 3 MW.

e. Filterable particulate matter (PM) is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

f. Expressed as SO_2. S equals the sulfur content expressed on $gr/100$ ft^3 gas vapor. For example, if the butane sulfur content is 0.18 $gr/100$ ft^3 emission factor would be (0.011 x 0.18) = 0.0020 kg of $SO_2/1000$ liters butane burned.

g. Expressed as NO_2.

References for Section 1.5

1.   Air Pollutant Emission Factors, Final Report, Contract No. CPA-22-69-119, Resources Research, Inc., Reston, VA, Durham, NC, April 1970.

2.   E. A. Clifford, A Practical Guide to Liquified Petroleum Gas Utilization, New York, Moore Publishing Co., 1962.

3.   Nitrous Oxide Reduction with the Weishaupt Flue Gas Recirculation System, Weishaupt Research and Development Institute, January. 1987.

4.   Phone communication memorandum dated May 14, 1992. Conversation between B. Lusher of Acurex Environmental and D. Childress of Suburban/Petrolane, Durham, NC.

1.6 WOOD WASTE COMBUSTION IN BOILERS

1.6.1 General[1-5]

The burning of wood waste in boilers is mostly confined to those industries where it is available as a byproduct. It is burned both to obtain heat energy and to alleviate possible solid waste disposal problems. In boilers, wood waste is normally burned in the form of hogged wood, sawdust, shavings, chips, sanderdust, or wood trim. Heating values for this waste range from about 2,200 to 2,700 kcal/kg (4,000 to 5,000 Btu/lb) of fuel on a wet, as-fired basis. The moisture content of as-fired wood is typically near 50, weight percent but may vary from 5 to 75 weight percent depending on the waste type and storage operations.

Generally, bark is the major type of waste burned in pulp mills; either a mixture of wood and bark waste or wood waste alone is burned most frequently in the lumber, furniture, and plywood industries. As of 1980, there were approximately 1,600 wood-fired boilers operating in the U. S., with a total capacity of over 30 GW (1.0×10^{11} Btu/hr).

1.6.2 Firing Practices[5-7]

Various boiler firing configurations are used for burning wood waste. One common type of boiler used in smaller operations is the Dutch oven. This unit is widely used because it can burn fuels with very high moisture content. Fuel is fed into the oven through an opening in the top of a refractory-lined furnace. The fuel accumulates in a cone-shaped pile on a flat or sloping grate. Combustion is accomplished in two stages: (1) drying and gasification, and (2) combustion of gaseous products. The first stage takes place in the primary furnace, which is separated from the secondary furnace chamber by a bridge wall. Combustion is completed in the secondary chamber before gases enter the boiler section. The large mass of refractory helps to stabilize combustion rates but also causes a slow response to fluctuating steam demand.

In another boiler type, the fuel cell oven, fuel is dropped onto suspended fixed grates and is fired in a pile. Unlike the Dutch oven, the refractory-lined fuel cell also uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Because of their overall design and operating similarities, however, fuel cell and Dutch oven boilers have comparable emission characteristics.

The most common firing method employed for wood-fired boilers larger than 45,000 kg/hr (100,000 lb/hr) steam generation rate is the spreader stoker. With this boiler, wood enters the furnace through a fuel chute and is spread either pneumatically or mechanically across the furnace, where small pieces of the fuel burn while in suspension. Simultaneously, larger pieces of fuel are spread in a thin, even bed on a stationary or moving grate. The burning is accomplished in three stages in a single chamber: (1) moisture evaporation; (2) distillation and burning of volatile matter; and (3) burning of fixed carbon. This type of operation has a fast response to load changes, has improved combustion control, and can be operated with multiple fuels. Natural gas or oil is often fired in spreader stoker boilers as auxiliary fuel. This is done to maintain constant steam when the wood waste supply fluctuates and/or to provide more steam than can be generated from the waste supply alone. Although spreader stokers are the most common stokers among larger wood-fired boilers, overfeed and underfeed stokers are also utilized for smaller units.

Another boiler type sometimes used for wood combustion is the suspension-firing boiler. This boiler differs from a spreader stoker in that small-sized fuel (normally less than 2 mm) is blown into the boiler and combusted by supporting it in air rather than on fixed grates. Rapid changes in

combustion rate and, therefore, steam generation rate are possible because the finely divided fuel particles burn very quickly.

A recent development in wood firing is the fluidized bed combustion (FBC) boiler. A fluidized bed consists of inert particles through which air is blown so that the bed behaves as a fluid. Wood waste enters in the space above the bed and burns both in suspension and in the bed. Because of the large thermal mass represented by the hot inert bed particles, fluidized beds can handle fuels with moisture contents up to near 70 percent (total basis). Fluidized beds can also handle dirty fuels (up to 30 percent inert material). Wood fuel is pyrolyzed faster in a fluidized bed than on a gate due to its immediate contact with hot bed material. As a result, combustion is rapid and results in nearly complete combustion of the organic matter, thereby minimizing emission of unburned organic compounds.

1.6.3 Emissions And Controls[6-11]

The major emission of concern from wood boilers is particulate matter (PM), although other pollutants, particularly carbon monoxide (CO) and organic compounds, may be emitted in significant quantities under poor operating conditions. These emissions depend on a number of variables, including (1) the composition of the waste fuel burned, (2) the degree of flyash reinjection employed and (3) furnace design and operating conditions.

The composition of wood waste depends largely on the industry from which it originates. Pulping operations, for example, produce great quantities of bark that may contain more than 70 weight percent moisture, sand, and other non-combustibles. As a result, bark boilers in pulp mills may emit considerable amounts of particulate matter to the atmosphere unless they are well controlled. On the other hand, some operations, such as furniture manufacturing, generate a clean, dry wood waste (e.g., 2 to 20 weight percent moisture) which produces relatively low particulate emission levels when properly burned. Still other operations, such as sawmills, burn a varying mixture of bark and wood waste that results in PM emissions somewhere between these two extremes.

Furnace design and operating conditions are particularly important when firing wood waste. For example, because of the high moisture content that may be present in wood waste, a larger than usual area of refractory surface is often necessary to dry the fuel before combustion. In addition, sufficient secondary air must be supplied over the fuel bed to burn the volatiles that account for most of the combustible material in the waste. When proper drying conditions do not exist, or when secondary combustion is incomplete, the combustion temperature is lowered, and increased PM, CO, and organic compound emissions may result. Short term emissions can fluctuate with significant variations in fuel moisture content.

Flyash reinjection, which is commonly used with larger boilers to improve fuel efficiency, has a considerable effect on PM emissions. Because a fraction of the collected flyash is reinjected into the boiler, the dust loading from the furnace and, consequently, from the collection device increase significantly per unit of wood waste burned. More recent boiler installations typically separate the collected particulate into large and small fractions in sand classifiers. The larger particles, which are mostly carbon, are reinjected into the furnace. The smaller particles, mostly inorganic ash and sand, are sent to ash disposal.

Currently, the four most common control devices used to reduce PM emissions from wood-fired boilers are mechanical collectors, wet scrubbers, electrostatic precipitators (ESPs), and fabric filters. The use of multitube cyclone (or multiclone) mechanical collectors provides particulate control for many hogged boilers. Often, two multiclones are used in series, allowing the first collector to

remove the bulk of the dust and the second to remove smaller particles. The efficiency of this arrangement is from 65 to 95 percent. The most widely used wet scrubbers for wood-fired boilers are venturi scrubbers. With gas-side pressure drops exceeding 4 kPa (15 inches of water), particulate collection efficiencies of 90 percent or greater have been reported for venturi scrubbers operating on wood-fired boilers.

Fabric filters (i.e., baghouses) and ESPs are employed when collection efficiencies above 95 percent are required. When applied to wood-fired boilers, ESPs are often used downstream of mechanical collector precleaners which remove larger-sized particles. Collection efficiencies of 93 to 99.8 percent for PM have been observed for ESPs operating on wood-fired boilers.

A variation of the ESP is the electrostatic gravel bed filter. In this device, PM in flue gases is removed by impaction with gravel media inside a packed bed; collection is augmented by an electrically charged grid within the bed. Particulate collection efficiencies are typically near 95 percent.

Fabric filters have had limited applications to wood-fired boilers. The principal drawback to fabric filtration, as perceived by potential users, is a fire danger arising from the collection of combustible carbonaceous fly ash. Steps can be taken to reduce this hazard, including the installation of a mechanical collector upstream of the fabric filter to remove large burning particles of fly ash (i.e., "sparklers"). Despite complications, fabric filters are generally preferred for boilers firing salt-laden wood. This fuel produces fine particulates with a high salt content. Fabric filters are capable of high fine particle collection efficiencies; in addition, the salt content of the particles has a quenching effect, thereby reducing fire hazards. In two tests of fabric filters operating on salt-laden wood-fired boilers, particulate collection efficiencies were above 98 percent.

Emissions of nitrogen oxides (NO_x) from wood-fired boilers are lower than those from coal-fired boilers due to the lower nitrogen content of wood and the lower combustion temperatures which characterize wood-fired boilers. In those areas of the U.S. where NO_x emissions must be reduced to their lowest levels, the application of selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) to waste wood-fired boilers has either been accomplished (SNCR) or is being contemplated (SCR). Both systems are post-combustion NO_x reduction techniques in which ammonia (or urea) is injected into the flue gas to selectively reduce NO_x to nitrogen and water. In one application of SNCR to an industrial wood-fired boiler, NO_x reduction efficiencies varied between 35 and 75 percent as the ammonia:NO_x ratio increased from 0.4 to 3.2.

Emission factors and emission factor ratings for wood waste boilers are summarized in Tables 1.6-1 through 1.6-9. Cumulative particle size distribution data and associated emission factors are presented in Tables 1.6-10 and 1.6-11. Uncontrolled and controlled size-specific emission factors are plotted in Figures 1.6-1 and 1.6-2. All emission factors presented are based on the feed rate of wet, as-fired wood.
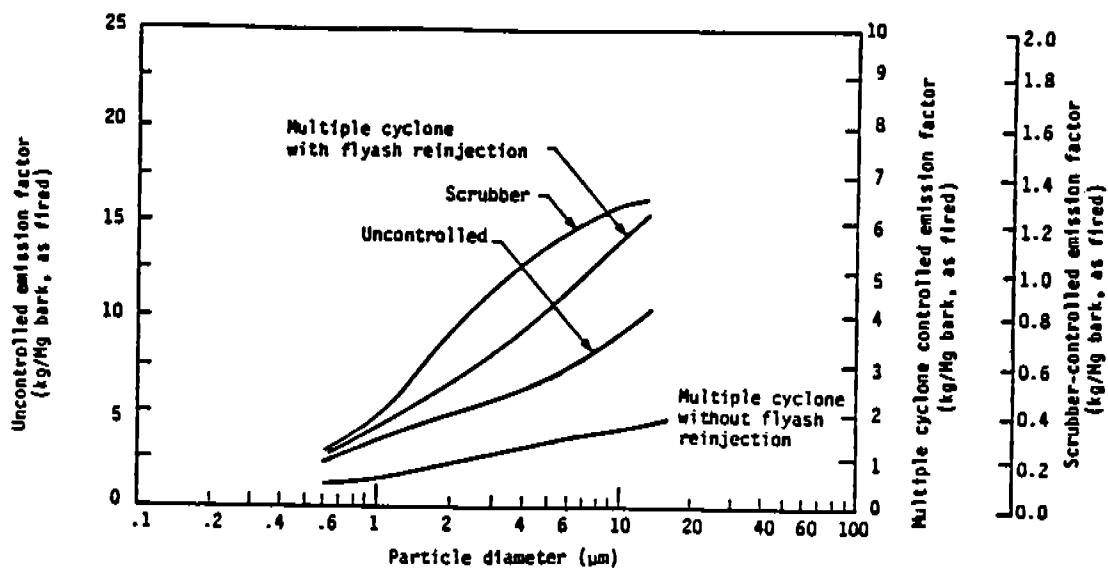
Figure 1.6-1. Cumulative size specific emission factors for bark fired boilers.
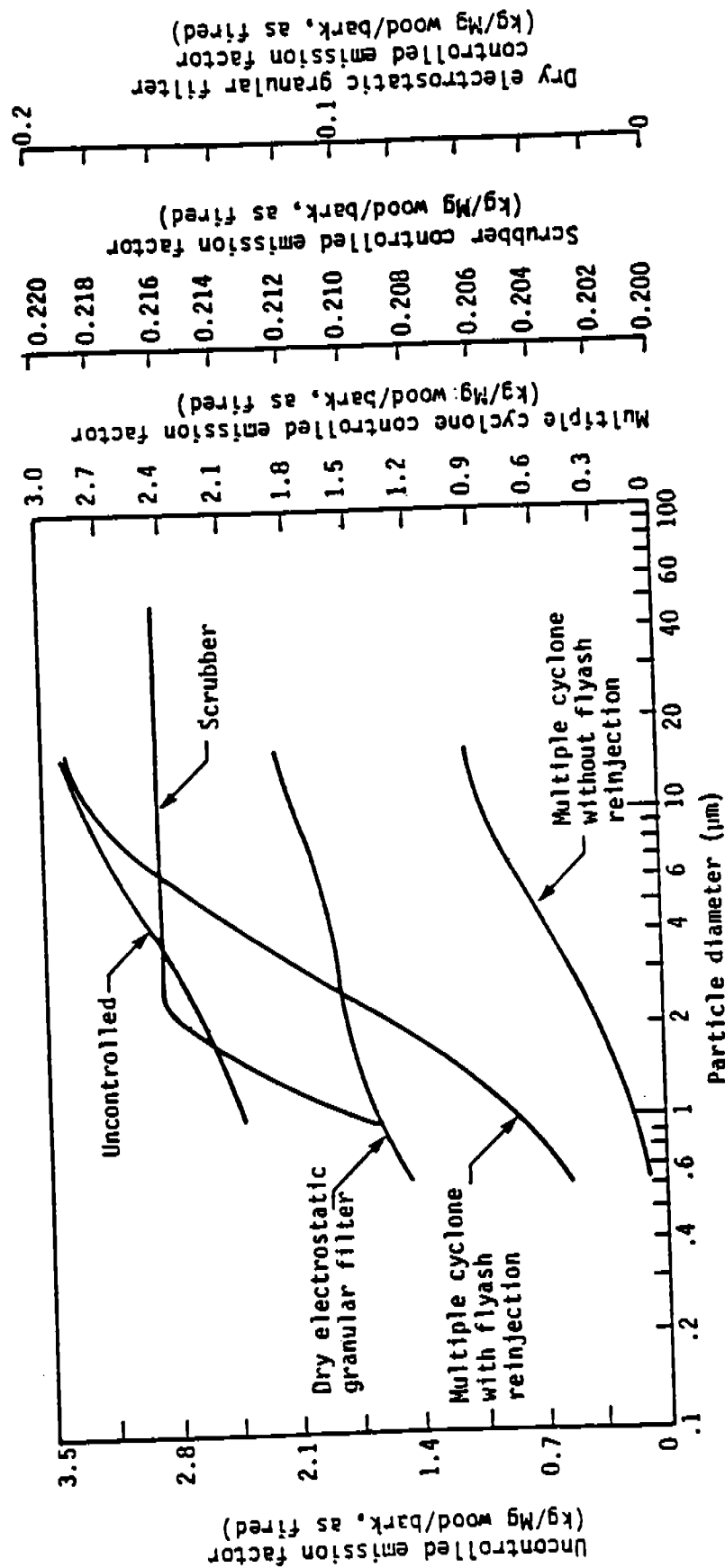
Figure 1.6-2. Cumulative size specific emission factors for wood/bark fired boilers.

TABLE 1.6-3 EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC) AND CARBON DIOXIDE (CO_2) FROM WOOD WASTE COMBUSTION[1,a]

| Source category[b] | TOC[c] | | | | CO_2 | | |
	kg/Mg	lb/ton	Rating		kg/Mg	lb/ton	Rating
Fuel cell/Dutch oven boilers	0.08	0.15	C		950	1900	B
Stoker boilers	0.09	0.18	C		1000	2000	B
FBC boilers[d]	NA	NA			900	1800	B

a. Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2500 kcal/kg (4500 Btu/lb) higher heating value.

b. After PM control device.

c. Emissions measured as total hydrocarbons, converted to kg carbon/Mg fuel (lb carbon/ton fuel).

d. FBC = Fluidized bed combustion

TABLE 1.6-2. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x), SULFUR OXIDES (SO_x), AND CARBON MONOXIDE (CO) FROM WOOD WASTE COMBUSTION[1,a]

Source category[b]	NO_x[c]			SO_x[d]			CO[e]		
	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating
Fuel cell/Dutch oven boiler	0.19 (0.0017-0.75)	0.38 (0.0033-1.5)	C	0.37 (0.005-0.1)	0.075 (0.01-0.2)	B	3.3 (0.33-11)	6.6 (0.65-21)	C
Stoker boilers	0.75 (0.33-1.8)	1.5 (0.66-3.6)	C	0.37 (0.005-0.1)	0.075 (0.01-0.2)	B	6.8 (0.95-40)	13.6 (1.9-80)	C
FBC boilers[f]	1.0	2.0	D	0.37 (0.005-0.1)	0.075 (0.01-0.2)	B	0.7 (0.24-1.2)	1.4 (0.47-2.4)	D

a. Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2,500 kcal/kg (4,500 Btu/lb) higher heating value.
b. After PM control device.
c. NO_x formation is primarily a function of wood nitrogen content. Higher values in the range (parentheses) should be used for wood nitrogen contents above a typical value of 0.08 weight percent, as fired.
d. Lower limit of the range (in parentheses) should be used for wood and higher values for bark.
e. Higher values in the range (in parentheses) should be used if combustion conditions are less than adequate, such as unusually wet wood or high air-to-fuel ratios.
f. FBC = Fluidized bed combustion.

TABLE 1.6-1. EMISSION FACTORS FOR PARTICULATE MATTER (PM), PARTICULATE MATTER LESS THAN 10 MICRONS (PM-10), AND LEAD FROM WOOD WASTE COMBUSTION[1,a]

Source category	PM			PM-10			Lead		
	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating
Barkfired boilers									
Uncontrolled	23.5	47	B	8.5	17	D	1.4E03	2.9E03	D
Mechanical collector									
with flyash reinjection	7	14	B	5.5	11	D	NA	NA	
without flyash reinjection	4.5	9.0	B	1.6	3.2	D			
Wet scrubber	1.5	2.9	D	1.3	2.5	D	NA	NA	
Wood/barkfired boilers									
Uncontrolled	3.6	7.2	C	3.2	6.5	E	NA	NA	
Mechanical collector									
with flyash reinjection	3.0	6.0	C	2.7	5.5	E	1.6E04[b]	3.2E-04[b]	D
without flyash reinjection	2.7	5.3	C	0.08	1.7	E			
Wet scrubber	0.24	0.48	D	0.23	0.47	E	1.8E04	3.5E-04	D
Electrostatic precipitator	0.02	0.04	D	NA	NA		8.0E05	1.6E-05	D
Woodfired boilers									
Uncontrolled	4.4	8.8	C	NA	NA		NA	NA	
Mechanical collector without flyash reinjection	2.1	4.2	C	1.3[c]	2.6[c]	E	1.5E04	3.1E04	D
Electrostatic precipitator	0.08	0.17	D	NA	NA		5.5E03	1.1E03	D

NA = Not available

a. Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2,500 kcal/kg (4,500 Btu/lb) higher heating value.

b. Due to lead's relative volatility, it is assumed that flyash reinjection does not have a significant effect on lead emissions following mechanical collectors.

c. Based on one test in which 61 percent of emitted PM was less than 10 micrometer in size.

TABLE 1.6-4. (ENGLISH UNITS) EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM WOOD WASTE COMBUSTION[1,a]

Organic Compound	Emission Factor Range lb/ton	Average Emission Factor lb/ton	Emission Factor Rating
Phenols	6.4E-05-1.2E-04	3.9E-04	C
Acenaphthene	8.6E-08-4.3E-06	3.4E-06	C
Fluorene	1.7E-07-2.8E-05	9.6E-06	C
Phenanthrene	2.0E-06-1.8E-04	5.7E-05	C
Anthracene	8.6E-08-3.5E-04	3.8E-05	C
Fluoranthene	8.6E-08-8.6E-04	9.0E-05	C
Pyrene	4.3E-07-5.9E-05	1.7E-05	C
Benzo(a)anthracene	8.6E-08-6.4E-06	1.8E-06	C
Benzo(b+k)fluoranthene	3.4E-07-1.9E-04	2.9E-05	C
Benzo(a)pyrene	8.6E-08-3.0E-07	1.9E-07	D
Benzo(g,h,i)perylene	8.6E-08-3.5E-06	1.2E-06	C
Chrysene	8.6E-08-3.0E-04	4.3E-05	C
Indeno(1,2,3,c,d)pyrene	8.6E-08-6.0E-07	3.4E-07	D
Polychlorinated dibenzo-p-dioxins	3.0E-09-3.3E-08	1.2E-08[b,c]	C
Polychlorinated dibenzo-p-furans	4.6E-09-7.2E-08	2.9E-08[b,d]	C
Acenaphthylene	6.0E-07-6.8E-05	4.4E-05	C
Pyrene		9.0E-06[e]	D
Methyl anthracene		1.4E-04[e]	D
Acrolein		4.0E-06[e]	D
Solicyladehyde		2.3E-05[e]	D
Benzaldehyde		1.2E-05[e]	D

a. Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 4500 Btu/lb higher heating value. Data measured after PM control device.
b. Emission factors are for total dioxins and furans, not toxic equivalents.
c. Excludes data from combustion of salt-laden wood. For salt-laden wood, emission factor is 1.3E-06 lb/ton with a D rating.
d. Excludes data from combustion of salt-laden wood. For salt-laden wood, emission factor is 5.5E-07 lb/ton with a D rating.
e. Based on data from one source test.

TABLE 1.6-5. (METRIC UNITS) EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM WOOD WASTE COMBUSTION[1,a]

Organic Compound	Emission Factor Range kg/Mg	Average Emission Factor kg/Mg	Emission Factor Rating
Phenols	3.2E-05-6.0E-05	1.9E-04	C
Acenaphthene	4.3E-08-2.1E-06	1.7E-06	C
Fluorene	8.5E-08-1.4E-05	4.8E-06	C
Phenanthrene	1.0E-06-9.0E-05	2.8E-05	C
Anthracene	4.3E-08-1.7E-04	1.9E-05	C
Fluoranthene	4.3E-08-4.3E-04	4.5E-05	C
Pyrene	2.1E-07-2.9E-05	8.5E-06	C
Benzo(a)anthracene	4.3E-08-3.2E-06	9.0E-07	C
Benzo(b+k)fluoranthene	1.7E-07-9.5E-05	1.9E-05	C
Benzo(a)pyrene	4.3E-08-1.5E-07	9.5E-08	D
Benzo(g,h,i)perylene	4.3E-08-1.7E-06	6.0E-07	C
Chrysene	4.3E-08-1.5E-04	2.1E-05	C
Indeno(1,2,3,c,d)pyrene	4.3E-08-3.0E-07	1.7E-07	D
Polychlorinated dibenzo-p-dioxins	1.5E-09-1.7E-08	6.0E-09[b,c]	C
Polychlorinated dibenzo-p-furans	2.3E-09-3.6E-08	1.5E-08[b,d]	C
Acenaphthylene	3.0E-07-3.4E-05	2.2E-05	C
Pyrene		4.5E-06[e]	D
Methyl anthracene		7.0E-05[e]	D
Acrolein		2.0E-06[e]	D
Solicyladehyde		1.1E-05[e]	D
Benzaldehyde		6.0E-06[e]	D

a. Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2500 kcal/kg higher heating value. Data measured after PM control device.
b. Emission factors are for total dioxins and furans, not toxic equivalents.
c. Excludes data from combustion of salt-laden wood. For salt-laden wood, emission factor is 6.5E-07 kg/Mg with a D rating.
d. Excludes data from combustion of salt-laden wood. For salt-laden wood, emission factor is 2.8E-07 kg/Mg with a D rating.
e. Based on data from one source test.

TABLE 1.6-6. (ENGLISH UNITS) EMISSION FACTORS FOR TRACE ELEMENTS FROM WOOD WASTE COMBUSTION[1,a]

Trace Element	Emission Factor Range lb/ton	Average Emission Factor lb/ton	Emission Factor Rating
Chromium (VI)	3.1E-05-5.9E-05	4.6E-05	D
Copper	1.4E-05-1.2E-03	1.9E-04	C
Zinc	9.9E-05-2.3E-02	4.4E-03	D
Barium		4.4E-03[b]	D
Potassium		7.8E-01[b]	D
Sodium		1.8E-02[b]	D
Iron	8.6E-04-8.7E-02	4.4E-02	D
Lithium		7.0E-05[b]	D
Boron		8.0E-04[b]	D
Chlorine		7.8E-03[b]	D
Vanadium		1.2E-04[b]	D
Cobalt		1.3E-04[b]	D
Thorium		1.7E-05[b]	D
Tungsten		1.1E-05[b]	D
Dysprosium		1.3E-05[b]	D
Samarium		2.0E-05[b]	D
Neodymium		2.6E-05[b]	D
Praeseodymium		3.0E-05[b]	D
Iodine		1.8E-05[b]	D
Tin		3.1E-05[b]	D
Molybdenum		1.9E-04[b]	D
Niobium		3.5E-05[b]	D
Zirconium		3.5E-04[b]	D
Yttrium		5.6E-05[b]	D
Rubidium		1.2E-03[b]	D
Bromine		3.9E-04[b]	D
Germanium		2.5E-06[b]	D

a.   Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 4500 Btu/lb higher heating value. Data measured after PM control device.

b.   Based on data from one source test.

TABLE 1.6-7. (METRIC UNITS) EMISSION FACTORS FOR TRACE ELEMENTS FROM WOOD WASTE COMBUSTION[1,a]

Trace Element	Emission Factor Range kg/Mg	Average Emission Factor kg/Mg	Emission Factor Rating
Chromium (VI)	1.5E-05-2.9E-05	2.3E-05	D
Copper	7.0E-06-6.0E-04	9.5E-05	C
Zinc	4.9E-05-1.1E-02	2.2E-03	C
Barium		2.2E-03[b]	D
Potassium		3.9E-01[b]	D
Sodium		9.0E-03[b]	D
Iron	4.3E-04-3.3E-02	2.2E-02	D
Lithium		3.5E-05[b]	D
Boron		4.0E-04[b]	D
Chlorine		3.9E-03[b]	D
Vanadium		6.0E-05[b]	D
Cobalt[b]		6.5E-05[b]	D
Thorium		8.5E-06[b]	D
Tungsten		5.5E-06[b]	D
Dysprosium		6.5E-06[b]	D
Samarium		1.0E-05[b]	D
Neodymium		1.3E-05[b]	D
Praeseodymium		1.5E-05[b]	D
Iodine		8.0E-06[b]	D
Tin		1.5E-05[b]	D
Molybdenum		9.5E-05[b]	D
Niobium		1.7E-05[b]	D
Zirconium		1.7E-04[b]	D
Yttrium		2.8E-05[b]	D
Rubidium		6.0E-04[b]	D
Bromine		1.8E-04[b]	D
Germanium		1.7E-06[b]	D

a.   Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2500 kcal/kg higher heating value. Data measured after PM control device.
b.   Based on data from one source test.

TABLE 1.6-8 (ENGLISH UNITS) EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS (HAPs) FROM WOOD WASTE COMBUSTION[1,a]

Hazardous Air Pollutant	Emission Factor Range lb/ton	Average Emission Factor lb/ton	Emission Factor Rating
Arsenic	1.4E-06-2.4E-04	8.8E-05	C
Cadmium	2.7E-06-5.4E-04	1.7E-05	C
Chromium	6.0E-06-4.6E-04	1.3E-04	C
Manganese	3.0E-04-5.2E-02	8.9E-03	C
Mercury	2.6E-06-2.1E-05	6.5E-06	C
Nickel	3.4E-05-5.8E-03	5.6E-04	C
Selenium	1.7E-05-1.8E-05	1.8E-05	D
Formaldehyde	2.3E-04-3.3E-02	6.6E-03	C
Acetaldehyde	6.1E-05-2.4E-02	3.0E-03	C
Benzene	8.6E-05-1.4E-02	3.6E-03	C
Naphthalene	5.0E-05-5.8E-03	2.3E-03	C
2,3,7,8-Tetrachlorodibenzo-p-dioxin	2.12E-011-5.11E-011	3.6E-011	D

a.   Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 4500 Btu/lb higher heating value. Data measured after PM control device.

TABLE 1.6-9 (METRIC UNITS) EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS (HAPs) FROM WOOD WASTE COMBUSTION[1,a]

Hazardous Air Pollutant	Emission Factor Range kg/Mg	Average Emission Factor kg/Mg	Emission Factor Rating
Arsenic	7.0E-07-1.2E-04	4.4E-05	C
Cadmium	1.3E-06-2.7E-04	8.5E-06	C
Chromium	3.0E-06-2.3E-04	6.5E-05	C
Manganese	1.5E-04-2.6E-02	4.4E-03	C
Mercury	1.3E-06-1.0E-05	3.7E-06	C
Nickel	1.7E-05-2.9E-03	2.8E-04	C
Selenium	8.5E-06-9.0E-06	8.8E-06	D
Formaldehyde	1.2E-04-1.6E-02	3.3E-03	C
Acetaldehyde	3.0E-05-1.2E-02	1.5E-03	C
Benzene	4.3E-05-7.0E-03	1.8E-03	C
Naphthalene	2.5E-05-2.9E-03	1.1E-03	C
2,3,7,8-Tetrachlorodibenzo-p-dioxin	1.1E-011-2.6E-011	1.8E-011	D

a.   Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2400 kcal/kg higher heating value. Data measured after PM control device.

TABLE 1.6-11. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTOR FOR WOOD/BARK-FIRED BOILERS[11,a]

(Emission Factor Rating: E [A for dry electrostatic granular filter (DEGF)])

Particle size[b] (µm)	Cumulative mass % ≤ stated size					Cumulative emission factor [kg/Mg (lb/ton) bark, as fired]				
	Uncontrolled[c]	Controlled				Uncontrolled[c]	Controlled			
		Multiple cyclone[c]	Multiple cyclone[d]	Scrubber[e]	DEGF		Multiple cyclone[f]	Multiple cyclone[d]	Scrubber[e]	DEGF[f]
15	94	96	35	98	77	3.38 (6.77)	2.88 (5.76)	0.95 (1.90)	0.216 (0.431)	0.123 (0.246)
10	90	91	32	98	74	3.24 (6.48)	2.73 (5.46)	0.86 (1.72)	0.216 (0.432)	0.118 (0.236)
6	86	80	27	98	69	3.10 (6.20)	2.40 (4.80)	0.73 (1.46)	0.216 (0.432)	0.110 (0.220)
2.5	76	54	16	98	65	2.74 (5.47)	1.62 (3.24)	0.43 (0.86)	0.216 (0.432)	0.104 (0.208)
1.25	69	30	84	96	61	2.48 (4.97)	0.90 (1.80)	0.22 (0.44)	0.211 (0.422)	0.098 (0.196)
1.00	67	24	6	95	58	2.41 (4.82)	0.72 (1.44)	0.16 (0.32)	0.209 (0.418)	0.093 (0.186)
0.625	NA	16	3	NA	51	NA	0.48 (0.96)	0.081 (0.162)	NA	0.082 (0.164)
TOTAL	100	100	100	100	100	3.6 (7.2)	3.0 (6.0)	2.7 (5.4)	0.22 (0.44)	0.16 (0.32)

NA = Not available.
a. Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2500 kcal/kg (4500 Btu/lb) higher heating value.
b. Expressed as aerodynamic equivalent diameter.
c. From data on underfeed stokers. May also be used as size distribution for wood-fired boilers.
d. From data on spreader stokers without flyash reinjection.
e. From data on Dutch ovens. Estimated control efficiency, 94%.
f. From data on spreader stokers with flyash reinjection.

TABLE 1.6-10. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTOR FOR BARK-FIRED BOILERS[11,a]
(Emission Factor Rating: D)[b]

Particle size[c] (μm)	Cumulative mass % ≤ stated size				Cumulative emission factor [kg/Mg (lb/ton) bark, as fired]			
	Uncontrolled	Controlled			Uncontrolled	Controlled		
		Multiple cyclone[d]	Multiple cyclone[e]	Scrubber[f]		Multiple cyclone[d]	Multiple cyclone[e]	Scrubber[f]
15	42	90	40	92	10.1 (20.2)	6.3 (12.6)	1.8 (3.6)	1.32 (2.64)
10	35	79	36	87	8.4 (16.8)	5.5 (11.0)	1.62 (3.24)	1.25 (2.50)
6	28	64	30	78	6.7 (13.4)	4.5 (9.0)	1.35 (2.7)	1.12 (2.24)
2.5	21	40	19	56	5.0 (10.0)	2.8 (5.6)	0.86 (1.72)	0.81 (1.62)
1.25	15	26	14	29	3.6 (7.2)	1.8 (3.6)	0.63 (1.26)	0.42 (0.84)
1.00	13	21	11	23	3.1 (6.2)	1.5 (3.0)	0.5 (1.0)	0.33 (0.66)
0.625	9	15	8	14	2.2 (4.4)	1.1 (2.2)	0.36 (0.72)	0.20 (0.40)
TOTAL	100	100	100	100	24 (48)	7 (14)	4.5 (9.0)	1.44 (2.88)

a. Based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2,500 kcal/kg (4,500 Btu/lb) higher heating value.
b. Data limited to spreader stoker boilers.
c. Expressed as aerodynamic equivalent diameter.
d. With flyash reinjection.
e. Without flyash reinjection.
f. Estimated control efficiency for scrubber, 94%.

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1.8 BAGASSE COMBUSTION IN SUGAR MILLS

1.8.1 Process Description[1-4]

Bagasse is the matted cellulose fiber residue from sugar cane that has been processed in a sugar mill. Previously, bagasse was burned as means of solid waste disposal. However, as the cost of fuel oil, natural gas, and electricity have increased, the definition of bagasse has changed from refuse to a fuel.

The U.S. sugar cane industry is located in the tropical and subtropical regions of Florida, Texas, Louisiana, Hawaii, and Puerto Rico. Except for Hawaii, where sugar cane production takes place year round, sugar mills operate seasonally from 2 to 5 months per year.

Sugar cane is a large grass with a bamboo-like stalk that grows 8 to 15 feet tall. Only the stalk contains sufficient sucrose for processing into sugar. All other parts of the sugar cane (i.e., leaves, top growth and roots) are termed "trash." The objective of harvesting is to deliver the sugar cane to the mill with a minimum of trash or other extraneous material. The cane is normally burned in the field to remove a major portion of the trash and to control insects and rodents. The three most common methods of harvesting are hand cutting, machine cutting, and mechanical raking. The cane that is delivered to a particular sugar mill will vary in trash and dirt content depending on the harvesting method and weather conditions. Inside the mill, cane preparation for extraction usually involves washing the cane to remove trash and dirt, chopping, and then crushing. Juice is extracted in the milling portion of the plant by passing the chopped and crushed cane through a series of grooved rolls. The cane remaining after milling is bagasse.

Bagasse is a fuel of varying composition, consistency, and heating value. These characteristics depend on the climate, type of soil upon which the cane is grown, variety of cane, harvesting method, amount of cane washing, and the efficiency of the milling plant. In general, bagasse has a heating value between 1,700 and 2,200 kcal/kg (3,000 and 4,000 Btu/lb) on a wet, as-fired basis. Most bagasse has a moisture content between 45 and 55 percent by weight.

Fuel cells, horseshoe boilers, and spreader stoker boilers are used to combust bagasse. Horseshoe boilers and fuel cells differ in the shapes of their furnace area but in other respects are similar in design and operation. In these boilers (most common among older plants), bagasse is gravity-fed through chutes and piles up on a refractory hearth. Primary and overfire combustion air flows through ports in the furnace walls; burning begins on the surface pile. Many of these units have dumping hearths that permit ash removal while the unit is operating.

In more-recently built sugar mills, bagasse is burned in spreader stoker boilers. Bagasse feed to these boilers enters the furnace through a fuel chute and is spread pneumatically or mechanically across the furnace, where part of the fuel burns while in suspension. Simultaneously, large pieces of fuel are spread in a thin, even bed on a stationary or moving grate. The flame over the grate radiates heat back to the fuel to aid combustion. The combustion area of the furnace is lined with heat exchange tubes (waterwalls).

1.8.2 Emissions and Controls[1-3]

The most significant pollutant emitted by bagasse-fired boilers is particulate matter, caused by the turbulent movement of combustion gases with respect to the burning bagasse and resultant ash. Emissions of SO_2 and NO_x are lower than conventional fossil fuels due to the characteristically low levels of sulfur and nitrogen associated with bagasse.

Auxiliary fuels (typically fuel oil or natural gas) may be used during startup of the boiler or when the moisture content of the bagasse is too high to support combustion. If fuel oil is used during these periods, SO_2 and NO_x emissions will increase. Soil characteristics such as particle size can affect the magnitude of PM emissions from the boiler. Mill operations can also influence the bagasse ash content by not properly washing and preparing the cane. Upsets in combustion conditions can cause increased emissions of carbon monoxide (CO) and unburned organics, typically measured as volatile organic compounds (VOCs) and total organic compounds (TOCs).

Mechanical collectors and wet scrubbers are commonly used to control particulate emissions from bagasse-fired boilers. Mechanical collectors may be installed in single cyclone, double cyclone, or multiple cyclone (i.e., multiclone) arrangements. The reported PM collection efficiency for mechanical collectors is 20 to 60 percent. Due to the abrasive nature of bagasse fly ash, mechanical collector performance may deteriorate over time due to erosion if the system is not well maintained.

The most widely used wet scrubbers for bagasse-fired boilers are impingement and venturi scrubbers. Impingement scrubbers normally operate at gas-side pressure drops of 5 to 15 inches of water; typical pressure drops for venturi scrubbers are over 15 inches of water. Impingement scrubbers are in greater use due to lower energy requirements and fewer operating and maintenance problems. Reported PM collection efficiencies for both scrubber types are 90 percent or greater.

Gaseous emissions (e.g., SO_2, NO_x, CO, and organics) may also be absorbed to a significant extent in a wet scrubber. Alkali compounds are sometimes utilized in the scrubber to prevent low pH conditions. If CO_2-generating compounds (such as sodium carbonate or calcium carbonate) are used, CO_2 emissions will increase.

Fabric filters and electrostatic precipitators have not been used to a significant extent for controlling PM from bagasse-fired boilers due to potential fire hazards (fabric filters) and relatively higher costs (both devices).

Emission factors and emission factor ratings for bagasse-fired boilers are shown in Table 1.8-1 (English units) and Table 1.8-2 (metric units).

TABLE 1.8-1. EMISSION FACTORS FOR BAGASSE-FIRED BOILERS[a]
(ENGLISH UNITS)

Pollutant	Emission factor		Rating
	lb/1,000 lb steam[b]	lb/ton bagasse[c]	
Particulate matter[d]			
Uncontrolled	3.9	15.6	C
Controlled			
Mechanical collector	2.1	8.4	D
Wet scrubber	0.4	1.6	B
PM-10[d]			
Controlled			
Wet scrubber	0.34	1.36	D
Carbon dioxide			
Uncontrolled[e]	390	1,560	A
Nitrogen oxides			
Uncontrolled	0.3	1.2	C
Polycyclic organic matter			
Uncontrolled[f]	2.5E-4	1.0E-3	D

a. Reference 5.
b. Based on 2 pounds of steam produced per pound of wet bagasse fired.
c. Based on wet, as-fired bagasse containing approximately 50 percent moisture, by weight.
d. Includes only filterable PM (i.e., that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
e. CO_2 emissions will increase following a wet scrubber in which CO_2-generating reagents (such as sodium carbonate or calcium carbonate) are used.
f. Based on measurements collected downstream of PM control devices which may have provided some removal of POM condensed on PM.

TABLE 1.8-2. EMISSION FACTORS FOR BAGASSE-FIRED BOILERS[a]
(METRIC UNITS)

Pollutant	Emission factor, g/kg steam[b]	Emission factor, kg/Mg bagasse[c]	Rating
Particulate matter[d]			
Uncontrolled	3.9	7.8	C
Controlled			
Mechanical collector	2.1	4.2	D
Wet scrubber	0.4	0.8	B
PM-10[d]			
Controlled			
Wet scrubber	0.34	0.68	D
Carbon dioxide			
Uncontrolled[e]	390	780	A
Nitrogen oxides			
Uncontrolled	0.3	0.6	C
Polycyclic organic matter			
Uncontrolled[f]	2.5E-4	5.0E-4	D

a. Reference 5.
b. Based on 2 kg of steam produced per kg of wet bagasse fired.
c. Based on wet, as-fired bagasse containing approximately 50 percent moisture, by weight.
d. Includes only filterable PM (i.e., that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
e. CO_2 emissions will increase following a wet scrubber in which CO_2-generating reagents (such as sodium carbonate or calcium carbonate) are used.
f. Based on measurements collected downstream of PM control devices which may have provided some removal of POM condensed on PM.

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1.9 RESIDENTIAL FIREPLACES

1.9.1 General[1,2]

Fireplaces are used primarily for aesthetic effects and secondarily as a supplemental heating source in houses and other dwellings. Wood is the most common fuel for fireplaces, but coal and densified wood "logs" may also be burned. The user intermittently adds fuel to the fire by hand.

Fireplaces can be divided into two broad categories, 1) masonry (generally brick and/or stone, assembled on site, and integral to a structure) and 2) prefabricated (usually metal, installed on site as a package with appropriate duct work).

Masonry fireplaces typically have large fixed openings to the fire bed and have dampers above the combustion area in the chimney to limit room air and heat losses when the fireplace is not being used. Some masonry fireplaces are designed or retrofitted with doors and louvers to reduce the intake of combustion air during use.

Prefabricated fireplaces are commonly equipped with louvers and glass doors to reduce the intake of combustion air, and some are surrounded by ducts through which floor level air is drawn by natural convection, heated and returned to the room. Many varieties of prefabricated fireplaces are now available on the market. One general class is the freestanding fireplace, the most common of which consists of an inverted sheet metal funnel and stovepipe directly above the fire bed. Another class is the "zero clearance" fireplace, an iron or heavy gauge steel firebox lined inside with firebrick and surrounded by multiple steel walls with spaces for air circulation. Some zero clearance fireplaces can be inserted into existing masonry fireplace openings, and thus are sometimes called "inserts." Some of these units are equipped with close fitting doors and have operating and combustion characteristics similar to wood stoves. (See Section 1.10, Residential Wood Stoves.)

Masonry fireplaces usually heat a room by radiation, with a significant fraction of the combustion heat lost in the exhaust gases and through fireplace walls. Moreover, some of the radiant heat entering the room goes toward warming the air that is pulled into the residence to make up for that drawn up the chimney. The net effect is that masonry fireplaces are usually inefficient heating devices. Indeed, in cases where combustion is poor, where the outside air is cold, or where the fire is allowed to smolder (thus drawing air into a residence without producing appreciable radiant heat energy), a net heat loss may occur in a residence using a fireplace. Fireplace heating efficiency may be improved by a number of measures that either reduce the excess air rate or transfer back into the residence some of the heat that would normally be lost in the exhaust gases or through fireplace walls. As noted above, such measures are commonly incorporated into prefabricated units. As a result, the energy efficiencies of prefabricated fireplaces are slightly higher than those of masonry fireplaces.

1.9.2 Emissions[1-13]

The major pollutants of concern from fireplaces are unburnt combustibles, including carbon monoxide, gaseous organics and particulate matter (i. e., smoke). Significant quantities of unburnt combustibles are produced because fireplaces are inefficient combustion devices, with high uncontrolled excess air rates and without any sort of secondary combustion. The latter is especially important in wood burning because of its high volatile matter content, typically 80 percent by dry weight. In addition to

unburnt combustibles, lesser amounts of nitrogen oxides and sulfur oxides are emitted.

Hazardous Air Pollutants (HAPs) are a minor, but potentially important component of wood smoke. A group of HAPs known as polycyclic organic matter (POM) includes potential carcinogens such as benzo(a)pyrene (BaP). POM results from the combination of free radical species formed in the flame zone, primarily as a consequence of incomplete combustion. Under reducing conditions, radical chain propagation is enhanced, allowing the buildup of complex organic material such as POM. The POM is generally found in or on smoke particles, although some sublimation into the vapor phase is probable.

Another important constituent of wood smoke is creosote. This tar-like substance will burn if the fire is hot enough, but at insufficient temperatures, it may deposit on surfaces in the exhaust system. Creosote deposits are a fire hazard in the flue, but they can be reduced if the chimney is insulated to prevent creosote condensation or if the chimney is cleaned regularly to remove any buildup.

Fireplace emissions are highly variable and are a function of many wood characteristics and operating practices. In general, conditions which promote a fast burn rate and a higher flame intensity enhance secondary combustion and thereby lower emissions. Conversely, higher emissions will result from a slow burn rate and a lower flame intensity. Such generalizations apply particularly to the earlier stages of the burning cycle, when significant quantities of combustible volatile matter are being driven out of the wood. Later in the burning cycle, when all volatile matter has been driven out of the wood, the charcoal that remains burns with relatively few emissions.

Emission factors and their ratings for wood combustion in residential fireplaces are given in Tables 1.9-1. and 1.9-2.

Table 1.9-1. (ENGLISH UNITS) EMISSION FACTORS FOR WOOD COMBUSTION IN RESIDENTIAL FIREPLACES

Device	Pollutant	Emission Factor[a] lb/ton	Rating
Fireplace	PM-10[b]	34.6	B
	Carbon Monoxide[c]	252.6	B
	Sulfur Oxides[d]	0.4	A
	Nitrogen oxides[e]	2.6	C
	Carbon Dioxide[f]	3398.8	C
	TOC (Total Organic Compounds)		
	Non-methane[g]	26.0	D[h]
	POM[i]	1.6E-3	E[j]
	Aldehydes[k]	2.4	E[j]
	Hydrocarbons[l]	175.4	D[h]

a. Units are in lb/ton (lbs. of pollutant/ton of dry wood burned).
b. References 2, 5, 7, 13; contains filterable and condensable particulate matter (PM); PM emissions are considered to be 100% PM-10 (i.e., PM with an aerodynamic diameter of 10μm or less).
c. References 2, 4, 5, 9, 13.
d. References 1, 8.
e. References 4, 9; expressed as NO_2.
f. References 5, 13
g. References 1, 7.
h. Data used to calculate the average emission factor were collected by various methods. While the emission factor may be representative of the source population in general, it should not be used to estimate emissions from a specific source.
i. Reference 2.
j. Data used to calculate the average emission factor were collected from a single fireplace and are not representative of the general source population.
k. Reference 11.
l. References 2, 4, 5.

Table 1.9-2. (METRIC UNITS) EMISSION FACTORS FOR WOOD COMBUSTION IN
RESIDENTIAL FIREPLACES

Device	Pollutant	Emission Factor[a] g/kg	Rating
Fireplace	PM-10[b]	17.3	B
	Carbon Monoxide[c]	126.3	B
	Sulfur Oxides[d]	0.2	A
	Nitrogen oxides[e]	1.3	C
	Carbon Dioxide[f]	1699.4	C
	TOC (Total Organic Compounds)		
	Non-methane[g]	13	D[h]
	POM[i]	0.8E-3	E[j]
	Aldehydes[k]	1.2	E[j]
	Hydrocarbons[l]	87.7	D[h]

a. Units are in g/kg (grams of pollutant/kg of dry wood burned).
b. References 2, 5, 7, 13; contains filterable and condensable particulate matter (PM); PM emissions are considered to be 100% PM-10 (i.e., PM with an aerodynamic diameter of 10μm or less).
c. References 2, 4, 5, 9, 13.
d. References 1, 8.
e. References 4, 9; expressed as NO_2.
f. References 5, 13
g. References 1, 7.
h. Data used to calculate the average emission factor were collected by various methods. While the emission factor may be representative of the source population in general, it should not be used to estimate emissions from a specific source.
i. Reference 2.
j. Data used to calculate the average emission factor were collected from a single fireplace and are not representative of the general source population.
k. Reference 11.
l. References 2, 4, 5.

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1.10 RESIDENTIAL WOOD STOVES

1.10.1 General[1-3]

Wood stoves are commonly used in residences as space heaters. They are used both as the primary source of residential heat and to supplement conventional heating systems.

Five different categories should be considered when estimating emissions from wood burning devices due to differences in both the magnitude and the composition of the emissions:

- the conventional wood stove,

- the noncatalytic wood stove,

- the catalytic wood stove,

- the pellet stove, and

- the masonry heater.

Among these categories, there are many variations in device design and operation characteristics.

The conventional stove category comprises all stoves without catalytic combustors not included in the other noncatalytic categories (i. e., noncatalytic and pellet). Conventional stoves do not have any emission reduction technology or design features and, in most cases, were manufactured before July 1, 1986. Stoves of many different airflow designs may be in this category, such as updraft, downdraft, crossdraft and S-flow.

Noncatalytic wood stoves are those units that do not employ catalysts but do have emission reducing technology or features. Typical noncatalytic design includes baffles and secondary combustion chambers.

Catalytic stoves are equipped with a ceramic or metal honeycomb device, called a combustor or converter, that is coated with a noble metal such as platinum or palladium. The catalyst material reduces the ignition temperature of the unburned volatile organic compounds (VOC) and carbon monoxide (CO) in the exhaust gases, thus augmenting their ignition and combustion at normal stove operating temperatures. As these components of the gases burn, the temperature inside the catalyst increases to a point at which the ignition of the gases is essentially self sustaining.

Pellet stoves are those fueled with pellets of sawdust, wood products, and other biomass materials pressed into manageable shapes and sizes. These stoves have active air flow systems and unique grate design to accommodate this type of fuel. Some pellet stove models are subject to the 1988 New Source Performance Standards (NSPS), while others are exempt due to a high air-to-fuel ratio (i.e., greater than 35-to-1).

Masonry heaters are large, enclosed chambers made of masonry products or a combination of masonry products and ceramic materials. These devices are exempt from the 1988 NSPS due to their weight (i.e., greater than 800 kg). Masonry heaters are gaining popularity as a cleaner burning and

heat efficient form of primary and supplemental heat, relative to some other types of wood heaters. In a masonry heater, a complete charge of wood is burned in a relatively short period of time. The use of masonry materials promotes heat transfer. Thus, radiant heat from the heater warms the surrounding area for many hours after the fire has burned out.

1.10.2 Emissions[4-30]

The combustion and pyrolysis of wood in wood stoves produce atmospheric emissions of particulate matter, carbon monoxide, nitrogen oxides, organic compounds, mineral residues, and to a lesser extent, sulfur oxides. The quantities and types of emissions are highly variable, depending on a number of factors, including stage of the combustion cycle. During initial burning stages, after a new wood charge is introduced, emissions (primarily VOCs) increase dramatically. After the initial period of high burn rate. There is a charcoal stage of the burn cycle, characterized by a slower burn rate and decreased emissions. Emission rates during this stage are cyclical, characterized by relatively long periods of low emissions and shorter episodes of emission spikes.

Particulate emissions are defined in this discussion as the total catch measured by the EPA Method 5H (Oregon Method 7) sampling train.[1] A small portion of wood stove particulate emissions includes "solid" particles of elemental carbon and wood. The vast majority of particulate emissions is condensed organic products of incomplete combustion equal to or less than 10 micrometers in aerodynamic diameter (PM-10). Although reported particle size data are scarce, one reference states that 95 percent of the particles emitted from a wood stove were less than 0.4 micrometers in size.[4]

Sulfur oxides (SO_x) are formed by oxidation of sulfur in the wood. Nitrogen oxides (NO_x) are formed by oxidation of fuel and atmospheric nitrogen. Mineral constituents, such as potassium and sodium compounds, are released from the wood matrix during combustion.

The high levels of organic compound and CO emissions are results of incomplete combustion of the wood. Organic constituents of wood smoke vary considerably in both type and volatility. These constituents include simple hydrocarbons of carbon numbers 1 through 7 (C1 - C7) (which exist as gases or which volatilize at ambient conditions) and complex low volatility substances that condense at ambient conditions. These low volatility condensible materials generally are considered to have boiling points below 300°C (572°F).

Polycyclic organic matter (POM) is an important component of the condensible fraction of wood smoke. POM contains a wide range of compounds, including organic compounds formed through incomplete combustion by the combination of free radical species in the flame zone. This group which is classified as a Hazardous Air Pollutant (HAP) under Title III of the 1990 Clean Air Act Amendments contains the sub-group of hydrocarbons called Polycyclic Aromatic Hydrocarbons (PAH).

Emission factors and their ratings for wood combustion in residential wood stoves, pellet stoves and masonry heaters are presented in Tables 1.10-1 through 1.10-8. These tables include emission factors for criteria pollutants (PM-10, CO, NO_x, SO_x), CO_2, Total Organic Compounds (TOC), speciated organic compounds, PAH, and some elements. The emission factors are presented by wood heater type. PM-10 and CO emission factors are further classified by stove certification category. Phase II stoves are those certified to meet the July 1, 1990 EPA standards; Phase I stoves meet the July 1, 1988 EPA standards; and Pre-Phase I stoves do not meet any of the EPA standards

but in most cases do meet the Oregon 1986 certification standards.[1] The emission factors for PM and CO in Tables 1.10-1 and 1.10-2 are averages, derived entirely from field test data obtained under actual operating conditions. Still, there is a potential for higher emissions from some wood stove, pellet stove and masonry heater models.

As mentioned, particulate emissions are defined as the total emissions equivalent to that collected by EPA Method 5H. This method employs a heated filter followed by three impingers, an unheated filter, and a final impinger. Particulate emissions factors are presented as values equivalent to that collected with Method 5H. Conversions are employed, as appropriate, for data collected with other methods. See Reference 2 for detailed discussions of EPA Methods 5H and 28.

Table 1.10-7 shows net efficiency by device type, determined entirely from field test data. Net or overall efficiency is the product of combustion efficiency multiplied by heat transfer efficiency. Wood heater efficiency is an important parameter used, along with emission factors and percent degradation, when calculating PM-10 emission reduction credits. Percent degradation is related to the loss in effectiveness of a wood stove control device or catalyst over a period of operation. Control degradation for any stove, including noncatalytic wood stoves, may also occur as a result of deteriorated seals and gaskets, misaligned baffles and bypass mechanisms, broken refractories, or other damaged functional components. The increase in emissions which can result from control degradation has not been quantified. However, recent wood stove testing in Colorado and Oregon should produce results which allow estimation of emissions as a function of stove age.

TABLE 1.10-1. (ENGLISH UNITS) EMISSION FACTORS FOR RESIDENTIAL
WOOD COMBUSTION[a]

| Pollutant/ EPA Certification[b] | Emission Factor Rating | Wood Stove Type[c] | | | Pellet Stove Type[d] | | Masonry Heater |
		Conv. lb/ton	Non-Cat lb/ton	Cat lb/ton	Certified lb/ton	Exempt lb/ton	Exempt[e] lb/ton
PM-10[f,g]							
Pre-Phase I	B	30.6	25.8	24.2			
Phase I	B		20.0	19.6			
Phase II	B		14.6	16.2	4.2		
All	B	30.6	19.6	20.4	4.2	8.8	5.6
Carbon Monoxide[f]							
Pre-Phase I	B	230.8					
Phase I	B			104.4			
Phase II	B		140.8	107.0	39.4		
All	B	230.8	140.8	104.8	39.4	52.2	149.0
Nitrogen Oxides[f]		2.8[h]		2.0[i]	13.8[i]		
Sulfur Oxides[f]	B	0.4	0.4	0.4	0.4		
Carbon Dioxide[j]	C				2,951.6	3,671.2	3,849.4
Total Organic Compounds[k]							
Methane	E	64.0		26.0			
Non-Methane	E	28.0		17.2			

a.   Units are in (lbs. of pollutant/ton of dry wood burned).
b.   Pre-Phase I = not certified to 1988 EPA emission standards; Phase I = certified to 1988 EPA emission standards; Phase II = certified to 1990 EPA emission standards; All = average of emission factors for all devices.
c.   Conv = Conventional; Non-Cat = Noncatalytic; Cat = Catalytic.
d.   Certified = Certified pursuant to 1988 NSPS; Exempt = Exempt from 1988 NSPS (i.e., air:fuel ratio >35:1).
e.   Exempt = Exempt from 1988 NSPS (i.e., weight >800 kg).
f.   References 5-13, 22-26, 28.
g.   Defined as equivalent to total catch by EPA method 5H train.
h.   Rating = C.
i.   Rating = E.
j.   References 12, 22-26, 28.
k.   References 14, 15, 18. The data used to develop the emission factors showed a high degree of variability within the source population. The use of these emission factors on specific sources may not be appropriate.

TABLE 1.10-2. (METRIC UNITS) EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]

Pollutant/ EPA Certification[b]	Emission Factor Rating	Wood Stove Type[c]			Pellet Stove Type[d]		Masonry Heater
		Conv. g/kg	Non-Cat g/kg	Cat g/kg	Certified g/kg	Exempt g/kg	Exempt[e] g/kg
PM-10[f,g]							
Pre-Phase I	B	15.3	12.9	12.1			
Phase I	B		10.0	9.8			
Phase II	B		7.3	8.1	2.1		
All	B	15.3	9.8	10.2	2.1	4.4	2.8
Carbon Monoxide[f]							
Pre-Phase I	B	115.4					
Phase I	B			52.2			
Phase II	B		70.4	53.5	19.7		
All	B	115.4	70.4	52.4	19.7	26.1	74.5
Nitrogen Oxides[f]		1.4[h]		1.0[i]	6.9[i]		
Sulfur Oxides[f]	B	0.2	0.2	0.2	0.2		
Carbon Dioxide[j]	C				1,475.8	1,835.6	1,924.7
Total Organic Compounds[k]							
Methane	E	32.0		13.0			
Non-Methane	E	14.0		8.6			

a. Units are in (grams of pollutant/kg of dry wood burned).
b. Pre-Phase I = not certified to 1988 EPA emission standards; Phase I = certified to 1988 EPA emission standards; Phase II = certified to 1990 EPA emission standards; All = average of emission factors for all devices.
c. Conv = Conventional; Non-Cat = Noncatalytic; Cat = Catalytic.
d. Certified = Certified pursuant to 1988 NSPS; Exempt = Exempt from 1988 NSPS (i.e., air:fuel ratio >35:1).
e. Exempt = Exempt from 1988 NSPS (i.e., weight >800 kg).
f. References 5-13, 22-26, 28.
g. Defined as equivalent to total catch by EPA method 5H train.
h. Rating = C.
i. Rating = E.
j. References 12, 22-26, 28.
k. References 14, 15, 18. The data used to develop the emission factors showed a high degree of variability within the source population. The use of these emission factors on specific sources may not be appropriate.

TABLE 1.10-3. (ENGLISH AND METRIC UNITS) ORGANIC COMPOUND EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[18]
(Emission Factor Rating: E)[a]

Compounds	WOOD STOVE TYPE[b]			
	Conventional		Catalytic	
	lb/ton	g/kg	lb/ton	g/kg
Ethane	1.470	0.735	1.376	0.688
Ethylene	4.490	2.245	3.482	1.741
Acetylene	1.124	0.562	0.564	0.282
Propane	0.358	0.179	0.158	0.079
Propene	1.244	0.622	0.734	0.367
i-Butane	0.028	0.014	0.010	0.005
n-Butane	0.056	0.028	0.014	0.007
Butenes[c]	1.192	0.596	0.714	0.357
Pentenes[d]	0.616	0.308	0.150	0.075
Benzene	1.938	0.969	1.464	0.732
Toluene	0.730	0.365	0.520	0.260
Furan	0.342	0.171	0.124	0.062
Methyl Ethyl Ketone	0.290	0.145	0.062	0.031
2-Methyl Furan	0.656	0.328	0.084	0.042
2,5-Dimethyl Furan	0.162	0.081	0.002	0.011
Furfural	0.486	0.243	0.146	0.073
O-Xylene	0.202	0.101	0.186	0.093

a. The data used to develop the emission factors showed a high degree of variability within the source population. The use of these emission factors on specific sources may not be appropriate.
b. Units are in lb/ton (lbs. of pollutant/ton of dry wood burned).
c. 1-butene, i-butene, t-2-butene, c-2-butene, 2-me-1-butene, 2-me-butene are reported as butenes.
d. 1-pentene, t-2-pentene, and c-2-pentene are reported as pentenes.

TABLE 1.10-4. (ENGLISH UNITS) POLYCYCLIC AROMATIC HYDROCARBON (PAH) EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]
(Emission Factor Rating: E)[b]

Pollutant	STOVE TYPE			
	Conventional[c] lb/ton	Noncatalytic[d] lb/ton	Catalytic[e] lb/ton	Exempt Pellet[f] lb/ton
PAH				
Acenaphthene	0.010	0.010	0.006	
Acenaphthylene	0.212	0.032	0.068	
Anthracene	0.014	0.009	0.008	
Benzo(a)Anthracene	0.020	<0.001	0.024	
Benzo(b)Fluoranthene	0.006	0.004	0.004	2.60E-05
Benzo(g,h,i)Fluoranthene		0.028	0.006	
Benzo(k)Fluoranthene	0.002	<0.001	0.002	
Benzo(g,h,i)Perylene	0.004	0.020	0.002	
Benzo(a)Pyrene	0.004	0.006	0.004	
Benzo(e)Pyrene	0.012	0.002	0.004	
Biphenyl		0.022		
Chrysene	0.012	0.010	0.010	7.52E-05
Dibenzo(a,h)Anthracene	0.000	0.004	0.002	
7,12-Dimethylbenz(a)Anthracene		0.004		
Fluoranthene	0.020	0.008	0.012	5.48E-05
Fluorene	0.024	0.014	0.014	
Indeno(1,2,3,cd)Pyrene	0.000	0.020	0.004	
9-Methylanthracene		0.004		
12-Methylbenz(a)Anthracene		0.002		
3-Methylchlolanthrene		<0.001		
1-Methylphenanthrene		0.030		
Naphthalene	0.288	0.144	0.186	
Nitronaphthalene		0.000		
Perylene		0.002		
Phenanthrene	0.078	0.118	0.489	3.32E-05
Phenanthrol		0.000		
Phenol		<0.001		
Pyrene	0.024	0.008	0.010	4.84E-05
PAH Total	0.730	0.500	0.414	

a. Units are in lb/ton (lbs. of pollutant/ton of dry wood burned).

b. The data used to develop these emission factors showed a high degree of variability within the source population and/or came from a small number of sources. The use of these emission factors on specific sources may not be appropriate.

c. Reference 18.

d. References 16,19-21.

e. References 15-19.

f. Reference 28. Exempt = Exempt from 1988 NSPS (i.e., air:fuel ratio >35:1).

TABLE 1.10-5. (METRIC UNITS) POLYCYCLIC AROMATIC HYDROCARBON (PAH)
EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]
(Emission Factor Rating: E)[b]

| Pollutant | STOVE TYPE | | | |
	Conventional[c] g/kg	Noncatalytic[d] g/kg	Catalytic[e] g/kg	Exempt Pellet[f] g/kg
PAH				
Acenaphthene	0.005	0.005	0.003	
Acenaphthylene	0.106	0.016	0.034	
Anthracene	0.007	0.004	0.004	
Benzo(a)Anthracene	0.010	<0.001	0.012	
Benzo(b)Fluoranthene	0.003	0.002	0.002	1.30E-05
Benzo(g,h,i)Fluoranthene		0.014	0.003	
Benzo(k)Fluoranthene	0.001	<0.001	0.001	
Benzo(g,h,i)Perylene	0.002	0.010	0.001	
Benzo(a)Pyrene	0.002	0.003	0.002	
Benzo(e)Pyrene	0.006	0.001	0.002	
Biphenyl		0.011		
Chrysene	0.006	0.005	0.005	3.76E-05
Dibenzo(a,h)Anthracene	0.000	0.002	0.001	
7,12-Dimethylbenz(a)Anthracene		0.002		
Fluoranthene	0.010	0.004	0.006	2.74E-05
Fluorene	0.012	0.007	0.007	
Indeno(1,2,3,cd)Pyrene	0.000	0.010	0.002	
9-Methylanthracene		0.002		
12-Methylbenz(a)Anthracene		0.001		
3-Methylchlolanthrene		<0.001		
1-Methylphenanthrene		0.015		
Naphthalene	0.144	0.072	0.093	
Nitronaphthalene		0.000		
Perylene		0.001		
Phenanthrene	0.039	0.059	0.024	1.66E-05
Phenanthrol		0.000		
Phenol		<0.001		
Pyrene	0.012	0.004	0.005	2.42E-05
PAH Total	0.365	0.250	0.207	

a. Units are in g/kg (grams of pollutant/kg of dry wood burned).
b. The data used to develop these emission factors showed a high degree of variability within the source population and/or came from a small number of sources. The use of these emission factors on specific sources may not be appropriate.
c. Reference 18.
d. References 16,19-21.
e. References 15-19.
f. Reference 28. Exempt = Exempt from 1988 NSPS (i.e., air:fuel ratio >35:1).

TABLE 1.10-6. (ENGLISH AND METRIC UNITS) TRACE ELEMENT EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]
(Emission Factor Rating: E)[b]

| Element | WOOD STOVE TYPE | | | | | |
| | Conventional | | Noncatalytic | | Catalytic | |
	lb/ton	g/kg	lb/ton	g/kg	lb/ton	g/kg
Cadmium (Cd)	2.2E-05	1.1E-05	2.0E-05	1.0E-05	4.6E-05	2.3E-05
Chromium (Cr)	<1.0E-06	<1.0E-06	<1.0E-06	<1.0E-05	<1.0E-06	<1.0-E06
Manganese (Mn)	1.7E-04	8.7E-05	1.4E-04	7.0E-05	2.2E-04	1.1E-04
Nickel (Ni)	1.4E-05	7.0E-06	2.0E-05	1.0E-05	2.2E-06	1.0E-06

a.   Units are in lb/ton (lbs. of pollutant/ton of dry wood burned) and g/kg (grams of pollutant/kg of dry wood burned). Emission factors are based on data from References 15 and 18.
b.   The data used to develop these emission factors showed a high degree of variability within the source population. The use of these emission factors on a specific source may not be appropriate.

TABLE 1.10-7. SUMMARY OF WOOD HEATER NET EFFICIENCIES[a]

Wood Heater Type	Net Efficiency (%)	Reference
Wood Stoves		
Conventional	54	27
Non-Catalytic	68	10, 13, 27
Catalytic	68	7, 27
Pellet Stoves[b]		
Certified	68	12
Exempt	56	28
Masonry Heaters		
All	58	29

a.   Net efficiency is a function of both combustion efficiency and heat transfer efficiency. The percentages shown here are based on data collected from in-home testing.
b.   Certified = Certified pursuant to 1988 NSPS.
     Exempt = Exempt from 1988 NSPS (i.e., air:fuel ratio >35:1).

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1.11 WASTE OIL COMBUSTION

1.11.1 General[1]

Waste, or used oil can be burned in a variety of combustion systems including industrial boilers; commercial/institutional boilers; space heaters; asphalt plants; cement and lime kilns; other types of dryers and calciners; and steel production blast furnaces. Boilers and space heaters consume the bulk of the waste oil burned. Space heaters are small combustion units [generally less than 0.1 GW (250,000 Btu/hr input)] that are common in automobile service stations and automotive repair shops where supplies of waste crankcase oil are available.

Boilers designed to burn No. 6 (residual) fuel oils or one of the distillate fuel oils can be used to burn waste oil, with or without modifications for optimizing combustion. As an alternative to boiler modification, the properties of waste oil can be modified by blending it with fuel oil, to the extent required to achieve a clean-burning fuel mixture.

1.11.2 Emissions and Controls

Waste oil includes used crankcase oils from automobiles and trucks, used industrial lubricating oils (such as metal working oils), and other used industrial oils (such as heat transfer fluids). When discarded, these oils become waste oils due to a breakdown of physical properties and to contamination by the materials they come in contact with. The different types of waste oils may be burned as mixtures or as single fuels where supplies allow; for example, some space heaters in automotive service stations burn waste crankcase oils.

Contamination of the virgin oils with a variety of materials leads to an air pollution potential when these oils are burned. Potential pollutants include particulate matter (PM), small particles below 10 micrometers in size (PM-10), toxic metals, organic compounds, carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), hydrogen chloride, and global warming gases (CO_2, methane).

Ash levels in waste oils are normally much higher than ash levels in either distillate oils or residual oils. Waste oils have substantially higher concentrations of most of the trace elements reported relative to those concentrations found in virgin fuel oils. However, because of the shift to unleaded gasoline, the concentration of lead in waste crankcase oils has continued to decrease in recent years. Without air pollution controls, higher concentrations of ash and trace metals in the waste fuel translate to higher emission levels of PM and trace metals than is the case for virgin fuel oils.

Low efficiency pretreatment steps, such as large particle removal with screens or coarse filters, are common prefeed procedures at oil-fired boilers. Reductions in total PM emissions can be expected from these techniques but little or no effects have been noticed on the levels of (PM-10) emissions.

Constituent chlorine in waste oils typically exceeds the concentration of chlorine in virgin distillate and residual oils. High levels of halogenated solvents are often found in waste oil as a result of inadvertent or deliberate additions of the contaminant solvents to the waste oils. Many efficient combustors can destroy more than 99.99 percent of the chlorinated solvents present in the fuel. However, given the wide array of combustor types which burn waste oils, the presence of these compounds in the emission stream cannot be ruled out.

The flue gases from waste oil combustion often contain organic compounds other than chlorinated solvents. At ppmw levels, several hazardous organic compounds have been found in waste oils. Benzene, toluene, polychlorinated biphenyls (PCBs) and polychlorinated dibenzo-d-dioxins are a

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few of the hazardous compounds that have been detected in waste oil samples. Additionally, these hazardous compounds may be formed in the combustion process as products of incomplete combustion.

Emission factors and emission factor ratings for waste oil combustion are shown in Tables 1.11-1 through 1.11-5. Emission factors have been determined for emissions from uncontrolled small boilers and space heaters combusting waste oil. The use of both blended and unblended fuels is included in the mix of combustion operations. Emission factors have also been developed for emissions from a batch asphalt plant that was controlled for particulate matter and speciated metals but uncontrolled for other pollutants.

TABLE 1.11-1. EMISSION FACTORS FOR PARTICULATE MATTER (PM), PARTICULATE MATTER LESS THAN 10 MICRONS (PM-10), AND LEAD FROM WASTE OIL COMBUSTORS[1]

Source category	PM^a			PM-10^a			Lead^b		
	lb/1000 gal	kg/m^3	Rating	lb/1000 gal	kg/m^3	Rating	lb/1000 gal	kg/m^3	Rating
Small boilers	61A	7.3A	C	51A	6.1A	C	55L	6.6L	D
Space heaters									
Vaporizing burner	2.8A	0.34A	D	NA	NA		0.41L	0.049L	D
Atomizing burner	64A	7.7A	D	57A	6.8A	E	50L	6.0L	D
Batch asphalt plant^c	0.27A	0.03A	D	NA	NA		0.1L	0.01L	D

NA = Not available

a.   A = weight percent ash in fuel. Multiply numeric value by A to obtain emission factor.
b.   L = weight percent lead in fuel. Multiply numeric value by L to obtain emission factor.
c.   Controlled by fabric filter; all other sources categories are uncontrolled.

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TABLE 1.11-2. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x), SULFUR OXIDES (SO_x), AND CARBON MONOXIDE (CO) FROM WASTE OIL COMBUSTORS[1]

Source category	NO_x			SO_x[a]			CO		
	lb/1000 gal	kg/m³	Rating	lb/1000 gal	kg/m³	Rating	lb/1000 gal	kg/m³	Rating
Small boilers	19	2.3	C	147S	17.6S	C	5	0.60	D
Space heaters									
Vaporizing burner	11	1.3	D	100S	12.0S	D	1.7	0.20	D
Atomizing burner	16	1.9	D	107S	12.8S	D	2.1	0.25	D

NA = Not available
a.   S = weight percent sulfur in fuel. Multiply numeric value by S to obtain emission factor.

TABLE 1.11-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), HYDROGEN CHLORIDE (HCl), AND CARBON DIOXIDE (CO_2) FROM WASTE OIL COMBUSTORS[1]

Source category	TOC			HCl[a]			CO_2		
	lb/1000 gal	kg/m³	Rating	lb/1000 gal	kg/m³	Rating	lb/1000 gal	kg/m³	Rating
Small boilers	0.1	0.01	D	66Cl	7.9Cl	C	19,850	2,380	C
Space heaters									
Vaporizing burner	0.1	0.01	D	NA	NA		22,700	2,730	D
Atomizing burner	0.1	0.01	D	NA	NA		24,400	2,930	D
Batch asphalt plant	NA	NA	D	15Cl	1.8Cl	D	51,800	6,210	D

NA = Not available
a.   Cl = weight percent chlorine in fuel. Multiply numeric value by Cl to obtain emission factor.

TABLE 1.11-4 EMISSION FACTORS FOR SPECIATED METALS FROM WASTE OIL COMBUSTORS[1]
(Emission Factor Rating = D)

Pollutant	Small boilers		Space heaters: Vaporizing burner		Space heaters: Atomizing burner		Batch asphalt plant	
	lb/1000 gal	kg/m³	lb/1000 gal	kg/m³	lb/1000 gal	kg/m³	lb/1000 gal	kg/m³
Antimony	NA	NA	3.4E-04	4.1E-05	4.5E-03	5.4E-04	NA	NA
Arsenic	1.1E-01	1.3E-02	1.1E-03	1.3E-04	6.0E-02	7.2E-03	6.2E-05	7.4E-06
Beryllium	NA	NA	NA	NA	3.9E-07	4.7E-05	NA	NA
Cadmium	9.3E-03	1.1E-03	1.5E-04	1.8E-05	1.2E-02	1.4E-03	2.2E-04	2.6E-05
Chromium	2.0E-02	2.4E-03	2.6E-01	3.1E-02	1.8E-01	2.2E-02	8.2E-03	9.8E-04
Cobalt	2.1E-04	2.5E-05	5.7E-03	6.8E-04	5.2E-03	6.2E-04	NA	NA
Manganese	6.8E-02	8.2E-03	2.2E-03	2.6E-04	5.0E-02	6.0E-03	NA	NA
Nickel	1.1E-02	1.3E-03	5.0E-02	6.0E-03	1.6E-01	1.9E-02	NA	NA
Selenium	NA	NA	NA	NA	NA	NA	NA	NA
Phosphorous	NA	NA	3.6E-02	4.3E-03	5.4E+00	6.5E+01	NA	NA

NA = Not available.

TABLE 1.11-5. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM WASTE OIL COMBUSTORS[1]

(Emission Factor Rating = D)

Pollutant	Space heaters: Vaporizing burner		Space heaters: Atomizing burner		Batch asphalt plant	
	lb/1000 gal	kg/m^3	lb/1000 gal	kg/m^3	lb/1000 gal	kg/m^3
Phenol	2.4E-03	2.9E-04	2.8E-05	3.3E-06	NA	NA
Dichlorobenzene	6.7E-06	8.0E-07	NA	NA	NA	NA
Naphthalene	1.3E-02	1.6E-03	9.4E-04	1.1E-04	NA	NA
Phenanthrene/anthracene	1.1E-02	1.3E-03	9.9E-05	1.2E-05	NA	NA
Dibutylphthalate	NA	NA	3.4E-05	4.0E-06	NA	NA
Butylbenzylphthalate	5.1E-04	6.1E-05	NA	NA	NA	NA
Bis(2-ethylhexyl)phthalate	2.2E-03	2.6E-04	NA	NA	NA	NA
Pyrene	7.0E-03	8.4E-04	5.1E-05	6.1E-06	NA	NA
Benz(a)anthracene/chrysene	4.0E-03	4.8E-04	NA	NA	NA	NA
Benzo(a)pyrene	4.0E-03	4.8E-04	NA	NA	NA	NA
Trichloroethylene	NA	NA	NA	NA	1.0E-01	1.2E-02

NA = Not available.

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2.2 AUTOMOBILE BODY INCINERATION

The information presented in this section has been reviewed but not updated since it was originally prepared because no recent data were found and it is rarely practiced today. Auto bodies are likely to be shredded or crushed and used as scrap metal in secondary metal production operations, which are discussed in Chapter 7.

2.2.1 Process Description

Auto incinerators consist of a single primary combustion chamber in which one or several partially stripped cars are burned. (Tires are removed.) Approximately 30 to 40 minutes is required to burn two bodies simultaneously.[2] As many as 50 cars per day can be burned in this batch-type operation, depending on the capacity of the incinerator. Continuous operations in which cars are placed on a conveyor belt and passed through a tunnel-type incinerator have capacities of more than 50 cars per 8-hour day.

2.2.2 Emissions and Controls[1]

Both the degree of combustion as determined by the incinerator design and the amount of combustible material left on the car greatly affect emissions. Temperatures on the order of 1200°F (650°C) are reached during auto body incineration.[2] This relatively low combustion temperature is a result of the large incinerator volume needed to contain the bodies as compared with the small quantity of combustible material. The use of overfire air jets in the primary combustion chamber increases combustion efficiency by providing air and increased turbulence.

In an attempt to reduce the various air pollutants produced by this method of burning, some auto incinerators are equipped with emission control devices. Afterburners and low-voltage electrostatic precipators have been used to reduce particulate emissions; the former also reduces some of the gaseous emissions.[3,4] When afterburners are used to control emissions, the temperature in the secondary combustion chamber should be at least 1500°F (815°C). Lower temperatures result in higher emissions. Emission factors for auto body incinerators are presented in Table 2.2-1. Particulate matter is likely to be mostly in the PM-10 range, but no data are available to support this hypothesis. Although no data are available, emissions of HCl are expected due to the increased use of clorinated plastic materials in automobiles.

Table 2.2-1. EMISSION FACTORS FOR AUTO BODY INCINERATION[a]
EMISSION FACTOR RATING: D

Pollutants	Uncontrolled		With Afterburner	
	lb/car	kg/car	lb/car	kg/car
Particulates[b]	2	0.9	1.5	0.68
Carbon monoxide[c]	2.5	1.1	Neg	Neg
TOC (as CH_4)[c]	0.5	0.23	Neg	Neg
Nitrogen oxides (NO_2)[d]	0.1	0.05	0.02	0.01
Aldehydes (HCOH)[d]	0.2	0.09	0.06	0.03
Organic acids (acetic)[d]	0.21	0.10	0.07	0.03

[a]Based on 250 lb (113 kg) of combustible material on stripped car body.
[b]References 2 and 4.
[c]Based on data for open burning and References 2 and 5.
[d]Reference 3.

References for Section 2.2

1. Air Pollutant Emission Factors Final Report, National Air Pollution Control Administration, Durham, NC, Contract Number CPA-22-69-119, Resources Research Inc. Reston, VA, April 1970.

2. E. R. Kaiser, and J. Tolcias, "Smokeless Burning of Automobile Bodies," Journal of the Air Pollution Control Association, 12:64-73, February 1962.

3. F. M. Alpiser, "Air Pollution from Disposal of Junked Autos," Air Engineering, 10:18-22, November 1968.

4. Private Communication with D. F. Walters, U.S. DHEW, PHS, Division of Air Pollution, Cincinnati, Ohio. July 19, 1963.

5. R. W. Gerstle, and D. A. Kemnitz, "Atmospheric Emissions from Open Burning," Journal of the Air Pollution Control Association, 17:324-327. May 1967.

2.3 CONICAL BURNERS

The information presented in this section has not been updated since it was originally prepared because no recent data were found. The use of conical burners is much less prevalent now than in the past and they are essentially obsolete.

2.3.1 Process Description[1]

Conical burners are generally truncated metal cones with screened top vents. The charge is placed on a raised grate by either conveyor or bulldozer; however, the use of a conveyor results in more efficient burning. No supplemental fuel is used, but combustion air is often supplemented by underfire air blown into the chamber below the grate and by overfire air introduced through peripheral openings in the shell.

2.3.2 Emissions and Controls

The quantities and types of pollutants released from conical burners are dependent on the composition and moisture content of the charged material, control of combustion air, type of charging system used, and the condition in which the incinerator is maintained. The most critical of these factors seems to be the level of maintenance on the incinerators. It is not uncommon for conical burners to have missing doors and numerous holes in the shell, resulting in excessive combustion air, low temperatures, and, therefore, high emission rates of combustible pollutants.[2]

Particulate control systems have been adapted to conical burners with some success. These control systems include water curtains (wet caps) and water scrubbers. Emission factors for conical burners are shown in Table 2.3-1.

TABLE 2.3-1. EMISSION FACTORS FOR WASTE INCINERATION IN CONICAL BURNERS WITHOUT CONTROLS[a]
EMISSION FACTOR RATING: D

Type of Waste	Particulates		Sulfur Oxides		Carbon Monoxide		NMOC		Nitrogen Oxides	
	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg
Municipal refuse[b]	20 (10 to 60)[c,d]	10	2	1	60	30	20	10	5	2.5
Wood refuse[e]	1[f] 7[g] 20[h]	0.5 3.5 10	0.1	0.05	130	65	11	5.5	1	0.5

a Moisture content as fired is approximately 50 percent for wood waste.
b Except for particulates, factors are based on comparison with other waste disposal practices.
c Use high side of range for intermittent operations charged with a bulldozer.
d Based on Reference 3.
e References 4 through 9.
f Satisfactory operation: properly maintained burner with adjustable underfire air supply and adjustable, tangential overfire air inlets, approximately 500 percent excess air and 370°C (700°F) exit gas temperature.
g Unsatisfactory operation: properly maintained burner with radial overfire air supply near bottom of shell, approximately 1200 percent excess air and 204°C (400°F) exit gas temperature.
h Very unsatisfactory operation: improperly maintained burner with radial overfire air supply near bottom of shell and many gaping holes in shell, approximately 1500 percent excess air and 204°C (400°F) exit gas temperature.

References for Section 2.3

1. Air Pollutant Emission Factors, Final Report, CPA-22-69-119, Resources Research Inc. Reston, VA. Prepared for National Air Pollution Control Administration, Durham, NC April 1970.

2. T. E. Kreichelt, Air Pollution Aspects of Teepee Burners, U. S. DHEW, PHS, Division of Air Pollution. Cincinnati, Ohio. PHS Publication Number 999-AP-28. September 1966.

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4. Private Communication with Public Health Service, Bureau of Solid Waste Management, Cincinnati, Ohio. October 31, 1969.

5. D. M. Anderson, J. Lieben, and V. H. Sussman, Pure Air for Pennsylvania, Pennsylvania State Department of Health, Harrisburg PA, November 1961. p.98.

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8. H. Droege, and G. Lee, The Use of Gas Sampling and Analysis for the Evaluation of Teepee Burners, Bureau of Air Sanitation, California Department of Public Health, (Presented at the 7th Conference on Methods in Air Pollution Studies, Los Angeles, CA, January 1965.)

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2.4 OPEN BURNING

2.4.1 General[1]

Open burning can be done in open drums or baskets, in fields and yards, and in large open dumps or pits. Materials commonly disposed of in this manner include municipal waste, auto body components, landscape refuse, agricultural field refuse, wood refuse, bulky industrial refuse, and leaves.

Current regulations prohibit open burning of hazardous waste. One exception is for open burning and detonation of explosives, particularly waste explosives that have the potential to detonate, and bulk military propellants which cannot safely be disposed of through other modes of treatment.

The following Source Classification Codes (SCCs) pertain to open burning:

Government
50100201   General Refuse
50100202   Vegetation Only

Commercial/Institutional
50200201   Wood
50200202   Refuse

Industrial
50300201   Wood/Vegetation/Leaves
50300202   Refuse
50300203   Auto Body Components
50300204   Coal Refuse Piles
50300205   Rocket Propellant

2.4.2 Emissions[1-22]

Ground-level open burning emissions are affected by many variables, including wind, ambient temperature, composition and moisture content of the debris burned, and compactness of the pile. In general, the relatively low temperatures associated with open burning increase emissions of particulate matter, carbon monoxide, and hydrocarbons and suppress emissions of nitrogen oxides. Sulfur oxide emissions are a direct function of the sulfur content of the refuse.

2.4.2.1 Municipal Refuse

Emission factors for the open burning of municipal refuse are presented in Table 2.4-1.

2.4.2.2 Automobile Components

Emission factors for the open burning of automobile components including upholstery, belts, hoses, and tires are presented in Table 2.4-1.

Emission factors for the burning of scrap tires only are presented in Tables 2.4-2 through 2.4-4. Although it is illegal in many states to dispose of tires using open burning, fires often occur at

Table 2.4-1
Emission Factors for Open Burning of Municipal Refuse
Emission Factor Rating: D

Source	Particulate	Sulfur Oxides	Carbon Monoxide	VOC[a]		Nitrogen Oxides
				Methane	Nonmethane	
Municipal Refuse[b]						
kg/Mg	8	0.5	42	6.5	15	3
lb/ton	16	1.0	85	13	30	6
Automobile Components[c]						
kg/Mg	50	Neg.	62	5	16	2
lb/ton	100	Neg.	125	10	32	4

[a] Data indicate that VOC emissions are approximately 25% methane, 8% other saturates, 18% olefins, 42% others (oxygenates, acetylene, aromatics, trace formaldehyde).
[b] References 2 and 7.
[c] Reference 2. Upholstery, belts, hoses, and tires burned together.

tire stockpiles and through illegal burning activities. Of the emission factors presented here are used to estimate emissions from an accidental tire fire, it should be kept in mind that emissions from burning tires are generally dependent on the burn rate of the tire. A greater potential for emissions exists at lower burn rates, such as when a tire is smoldering, rather than burning out of control. In addition, the emission factors presented here for tire "chunks" are probably more appropriate than for "shredded" tire for estimating emissions from an accidental tire fire because there is likely to be more air-space between the tires in an actual fire. As discussed in Reference 21, it is difficult to estimate emissions from a large pile of tires based on these results, but emissions can be related to a mass burn rate. To use the information presented here, it may be helpful to use the following estimates: tires tested in Reference 21 weighed approximately 7 kilograms and one volume of one tire is approximately 7 ft^3 (15 pounds). Table 2.4-2 presents emission factors for particulate metals. Table 2.4-3 presents emission factors for polycyclic aromatic hydrocarbons (PAH's), and Table 2.4-4 presents emissions for other volatile hydrocarbons. For more detailed information on this subject consult the reference cited at the end of this chapter.

2.4.2.3 Agricultural Waste

Organic Agricultural Waste. Organic refuse burning consists of burning field crops, wood, and leaves. Emissions from organic agricultural refuse burning are dependent mainly on the moisture content of the refuse and, in the case of the field crops, on whether the refuse is burned in a headfire or a backfire. Headfires are started at the upwind side of a field and allowed to progress in the direction of the wind, whereas backfires are started at the downwind edge and forced to progress in a direction opposing the wind.

Other variables such as fuel loading (how much refuse material is burned per unit of land area) and how the refuse is arranged (in piles, rows, or spread out) are also important in certain instances. Emission factors for open agricultural burning are presented in Table 2.4-5 as a function

Table 2.4-2

Particulate Metals Emission Factors from Open Burning of Tires[a]

Emission Factor Rating: C

Tire Condition	Chunk[b]		Shredded[b]	
Pollutant	$\dfrac{mg}{kg\ tire}$	$\dfrac{lb}{1000\ tons\ tire}$	$\dfrac{mg}{kg\ tire}$	$\dfrac{lb}{1000\ tons\ tire}$
Aluminum	3.07	6.14	2.37	4.73
Antimony	2.94	5.88	2.37	4.73
Arsenic	0.05	0.10	0.20	0.40
Barium	1.46	2.92	1.18	2.35
Calcium	7.15	14.30	4.73	9.47
Chromium	1.97	3.94	1.72	3.43
Copper	0.31	0.62	0.29	0.58
Iron	11.80	23.61	8.00	15.99
Lead	0.34	0.67	0.10	0.20
Magnesium	1.04	2.07	0.75	1.49
Nickel	2.37	4.74	1.08	2.15
Selenium	0.06	0.13	0.20	0.40
Silicon	41.00	82.00	27.52	55.04
Sodium	7.68	15.36	5.82	11.63
Titanium	7.35	14.70	5.92	11.83
Vanadium	7.35	14.70	5.92	11.83
Zinc	44.96	89.92	24.75	49.51

[a]Reference 21.
[b]Values are weighted averages

Table 2.4-3

Polycyclic Aromatic Hydrocarbon Emission Factors From Open Burning Tires[a]

Emission Factor Rating: D

Tire Condition	Chunk[b,c]		Shredded[b,c]	
Pollutant	mg / kg tire	lb / 1000 tons tire	mg / kg tire	lb / 1000 tons tire
Acenaphthene	718.20	1436.40	2385.60	4771.20
Acenaphthylene	570.20	1140.40	568.08	1136.17
Anthracene	265.60	531.20	49.61	99.23
Benzo(A)pyrene	173.80	347.60	115.16	230.32
Benzo(B)fluoranthene	183.10	366.20	89.07	178.14
Benzo(G,H,I)perylene	36.20	72.40	160.84	321.68
Benzo(K)fluoranthene	281.80	563.60	100.24	200.48
Benz(A)anthracene	7.90	15.80	103.71	207.43
Chrysene	48.30	96.60	94.83	189.65
Dibenz(A,H)anthracene	54.50	109.00	0.00	0.00
Fluoranthene	42.30	84.60	463.35	926.69
Fluorene	43.40	86.80	189.49	378.98
Indeno(1,2,3-CD)pyrene	58.60	117.20	86.38	172.76
Naphthalene	0.00	0.0	490.85	981.69
Phenanthrene	28.00	56.00	252.73	505.46
Pyrene	35.20	70.40	153.49	306.98

[a]Reference 21.
[b]0.00 values indicate pollutant was not found.
[c]Values are weighted averages.

Table 2.4-4

Emission Factors for Organic Compounds from Open Burning of Tires[a]

Emission Factor Rating: C

Tire condition	Chunk[b,c]		Shredded[b,c]	
Pollutant	$\frac{mg}{kg\ tire}$	$\frac{lb}{1000\ tons\ tire}$	$\frac{mg}{kg\ tire}$	$\frac{lb}{1000\ tons\ tire}$
1,1'biphenyl, methyl	12.71	25.42	0.00	0.00
1h fluorene	191.27	382.54	315.18	630.37
1-methyl naphthalene	299.20	598.39	227.87	455.73
2-methyl naphthalene	321.47	642.93	437.06	874.12
Acenaphthalene	592.70	1185.39	549.32	1098.63
Benzaldehyde	223.34	446.68	322.05	644.10
Benzene	1526.39	3052.79	1929.93	3859.86
Benzodiazine	13.12	26.23	17.43	34.87
Benzofuran	40.62	81.24	0.00	0.00
Benzothiophene	10.31	20.62	914.91	1829.82
Benzo(B)thiophene	50.37	100.74	0.00	0.00
Benzsisothiazole	0.00	0.00	151.66	303.33
Biphenyl	190.08	380.16	329.65	659.29
Butadiene	117.14	234.28	138.97	277.95
Cyanobenzene	203.81	407.62	509.34	1018.68
Cyclopentadiene	67.40	134.80	0.00	0.00

Table 2.4-4 (Continued)

Tire condition	Chunk[b,c]		Shredded[b,c]	
Pollutant	mg/kg tire	lb/1000 tons tire	mg/kg tire	lb/1000 tons tire
Dihydroindene	9.82	19.64	30.77	61.53
Dimethyl benzene	323.58	647.16	940.91	1881.83
Dimethyl hexadiene	6.22	12.44	73.08	146.15
Dimethyl naphthalene	35.28	70.55	155.28	310.57
Dimethyldihydro indene	5.02	10.04	27.60	55.20
Ethenyl, dimethyl benzene	11.50	23.01	196.34	392.68
Ethenyl, methyl benzene	12.48	24.95	21.99	43.98
Ethenyl benzene	539.72	1079.44	593.15	1186.31
Ethenyl cyclohexene	4.85	9.70	89.11	178.22
Ethenylmethyl benzene	103.13	206.26	234.59	469.19
Ethyenylmethly benzene	0.00	0.00	42.04	84.07
Ethyl, methyl benzene	79.29	158.58	223.79	447.58
Ethyt benzene	138.94	277.87	335.12	670.24
Ethynyl, methyl benzene	459.31	918.62	345.25	690.50
Ethynyl benzene	259.82	519.64	193.49	386.98
Heptadiene	6.40	12.79	42.12	84.24
Hexahydro azepinone	64.35	128.69	764.03	1528.05

Table 2.4-4 (Continued)

| Tire condition | Chunk[b,c] | | Shredded[b,c] | |
Pollutant	$\frac{mg}{kg\ tire}$	$\frac{lb}{1000\ tons\ tire}$	$\frac{mg}{kg\ tire}$	$\frac{lb}{1000\ tons\ tire}$
Indene	472.74	945.48	346.23	692.47
Isocyano benzene	283.78	567.55	281.13	562.25
Isocyano naphthalene	10.75	21.51	0.00	0.00
Limonene	48.11	96.22	2309.57	4619.14
Methyl, ethenyl benzene	21.15	42.30	67.05	134.10
Methyl, methylethenyl benzene	35.57	71.13	393.78	787.56
Methyl, methylethyl benzene	109.69	219.39	1385.03	2770.07
Methyl benzaldehyde	0.00	0.00	75.49	150.98
Methyl benzene	1129.80	2259.60	1395.04	2790.08
Methyl cyclohexene	3.91	7.83	33.44	66.88
Methyl hexadiene	15.59	31.18	102.20	204.40
Methyl indene	50.04	100.07	286.68	573.36
Methyl,methylethyl benzene	11.76	23.52	114.33	228.66
Methyl naphthalene	144.78	289.56	122.68	245.37
Methyl,propyl benzene	0.00	0.00	30.14	60.28
Methyl thiophene	4.39	8.78	10.52	21.03
Methylene indene	30.37	60.75	58.91	117.82

Solid Waste Disposal

Table 2.4-4 (Continued)

Tire condition	Chunk[b,c]		Shredded[b,c]	
Pollutant	$\dfrac{mg}{kg\ tire}$	$\dfrac{lb}{1000\ tons\ tire}$	$\dfrac{mg}{kg\ tire}$	$\dfrac{lb}{1000\ tons\ tire}$
Methylethyl benzene	41.40	82.79	224.23	448.46
Phenol	337.71	675.41	704.90	1409.80
Propenyl, methyl benzene	0.00	0.00	456.59	913.18
Propenyl naphthalene	26.80	53.59	0.00	0.00
Propyl benzene	19.43	38.87	215.13	430.26
Styrene	618.77	1237.53	649.92	1299.84
Tetramethyl benzene	0.00	0.00	121.72	243.44
Thiophene	17.51	35.02	31.11	62.22
Trichlorofluoromethane	138.10	276.20	0.00	0.00
Trimethyl benzene	195.59	391.18	334.80	669.59
Trimethyl naphthalene	0.00	0.00	316.26	632.52

[a]Reference 21.
[b]0.00 values indicate the pollutant was not found.
[c]Values are weight averages.

TABLE 2.4-5. EMISSION FACTORS AND FUEL LOADING FACTORS FOR OPEN BURNING OF AGRICULTURAL MATERIALS EMISSION FACTOR RATING: D

Refuse Category	Particulate[b]		Carbon Monoxide		VOC[c]				Fuel Loading Factors (waste production)	
					Methane		Nonmethane			
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	Mg/hectare	ton/acre
Field Crops[d] Unspecified	11	21	58	117	2.7	5.4	9	18	4.5	2
Burning techniques not significant[e]										
Asparagus[f]	20	40	75	150	10	20	33	66	3.4	1.5
Barley	11	22	78	157	2.2	4.5	7.5	15	3.8	1.7
Corn	7	14	54	108	2	4	6	12	9.4	4.2
Cotton	4	8	88	176	0.7	1.4	2.5	5	3.8	1.7
Grasses	8	16	50	101	2.2	4.5	7.5	15		
Pineapple[g]	4	8	56	112	1	2	3	6		
Rice[h]	4	9	41	83	1.2	2.4	4	8	6.7	3.0
Safflower	9	18	72	144	3	6	10	20	2.9	1.3
Sorghum	9	18	38	77	1	2	3.5	7	6.5	2.9
Sugar cane[i]	2.3-3.5	6-8.4	30-41	60-81	0.6-2	1.2-3.8	2-6	4-12	8-46	3-17
Headfire Burning[j]										
Alfalfa	23	45	53	106	4.2	8.5	14	28	1.8	0.8
Bean (red)	22	43	93	186	5.5	11	18	36	5.6	2.5
Hay (wild)	16	32	70	139	2.5	5	8.5	17	2.2	1.0
Oats	22	44	68	137	4	7.8	13	26	3.6	1.6
Pea	16	31	74	147	4.5	9	15	29	5.6	2.5
Wheat	11	22	64	128	2	4	6.5	13	4.3	1.9

TABLE 2.4-5. (Continued)

Refuse Category	Particulate[b]		Carbon Monoxide		VOC[c]				Fuel Loading Factors (waste production)	
					Methane		Nonmethane			
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	Mg/hectare	ton/acre
Backfire Burning[k]										
Alfalfa	14	29	60	119	4.5	9	14	29	1.8	0.8
Bean (red)	7	14	72	148	3	6	10	19	5.6	2.5
Hay (wild)	8	17	75	150	2	4	6.5	13	2.2	1.0
Oats	11	21	68	136	2	4	7	14	3.6	1.6
Wheat	6	13	54	108	1.3	2.6	4.5	9	4.3	1.9
Vine Crops	3	5	26	51	0.8	1.7	3	5	5.6	2.5
Weeds										
Unspecified	8	15	42	85	1.5	3	4.5	9	7.2	3.2
Russian thistle (tumbleweed)	11	22	154	309	0.2	0.5	0.8	1.5	0.2	0.1
Tales (wild reeds)	3	5	17	34	3.2	6.5	10	21		
Orchard Crops[d,l,m]										
Unspecified	3	6	26	52	1.2	2.5	4	8	3.6	1.6
Almond	3	6	23	46	1	2	3	6	3.6	1.6
Apple	2	4	21	42	0.5	1	1.5	3	5.2	2.3
Apricot	3	6	24	49	1	2	3	6	4	1.8
Avocado	10	21	58	116	3.8	7.5	12	25	3.4	1.5
Cherry	4	8	22	44	1.2	2.5	4	8	2.2	1.0
Citrus (orange, lemon)	3	6	40	81	1.5	3	5	9	2.2	1.0
Date palm	5	10	28	56	0.8	1.7	3	5	2.2	1.0
Fig	4	7	28	57	1.2	2.5	4	8	4.9	2.2
Nectarine	2	4	16	33	0.5	1	1.5	3	4.5	2.0

TABLE 2.4-5. (Continued)

Refuse Category	Particulate[b]		Carbon Monoxide		VOC[c]				Fuel Loading Factors (waste production)	
					Methane		Nonmethane			
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	Mg/hectare	ton/acre
Orchard Crops[d,l,m]										
Olive	6	12	57	114	2	4	7	14	2.7	1.2
Peach	3	6	21	42	0.6	1.2	2	4	5.6	2.5
Pear	4	9	28	57	1	2	3.5	7	5.8	2.6
Prune	2	3	24	47	1	2	3	6	2.7	1.2
Walnut	3	6	24	47	1	2	3	6	2.7	1.2
Forest Residues[n]										
Unspecified	8	17	70	140	2.8	5.7	9	19	157	70
Hemlock, Douglas fir, cedar[p]	2	4	45	90	0.6	1.2	2	4		
Ponderosa pine[q]	6	12	98	195	1.7	3.3	5.5	11		

a Expressed as weight of pollutant emitted/weight of refuse material burned.
b Reference 12. Particulate matter from most agricultural refuse burning has been found to be in the submicrometer size range.
c Data indicate that VOC emissions average 22% methane, 7.5% other saturates, 17% olefins, 15% acetylene, 38.5% unidentified. Unidentified VOC are expected to include aldehydes, ketones, aromatics, cycloparaffins.
d References 12 - 13 for emission factors, Reference 14 for fuel loading factors.
e For these refuse materials, no significant difference exists between emissions from headfiring and backfiring.
f Factors represent emissions under typical high moisture conditions. If ferns are dried to <15% moisture, particulate emissions will be reduced by 30%, CO emission 23%, VOC emissions 74%.
g Reference 11. When pineapple is allowed to dry to <20% moisture, as it usually is, firing technique is not important. When headfired at 20% moisture, particulate emissions will increase to 11.5 kg/Mg (23 lb/ton) and VOC will increase to 6.5 kg/Mg (13 lb/ton).

TABLE 2.4-5. (Continued)

h   Factors are for dry (15% moisture) rice straw. If rice straw is burned at higher moisture levels, particulate emissions will increase to 14.5 kg/Mg (29 lb/ton), CO emissions to 80.5 kg/Mg (181 lb/ton), and VOC emissions to 11.5 kg/Mg (23 lb/ton).

i   See Section 8.12 for discussion of sugar cane burning. The following fuel loading factors are to be used in the corresponding states: Louisiana, 8 - 13.6 Mg/hectare (3 - 5 ton/acre); Florida, 11 - 19 Mg/hectare (4 - 7 ton/acre); Hawaii, 30 - 48 Mg/hectare (11 - 17 ton/acre). For other areas, values generally increase with length of growing season. Use larger end of the emission factor range for lower loading factors.

j   See text for definition of headfiring.

k   See text for definition of backfiring. This category, for emission estimation purposes, includes another technique used occasionally to limit emissions, called into-the-wind striplighting, which is lighting fields in strips into the wind at 100 - 200 meter (300 - 600 feet) intervals. There are no significant differences in emissions between burning a "cold pile" and using a roll-on technique, where prunings are bulldozed onto the embers of a preceding fire.

l   Orchard prunings are usually burned in piles.

m   If orchard removal is the purpose of a burn, 66 Mg/hectare (30 ton/acre) of waste will be produced.

n   Reference 10. NO$_x$ emissions estimated at 2 kg/Mg (4 lb/ton).

o   Reference 15.

p   Reference 16.

TABLE 2.4-6. EMISSION FACTORS FOR LEAF BURNING[a]
EMISSION FACTOR RATING: D

| Leaf Species | Particulate[b] | | Carbon Monoxide | | VOC[c] | | | |
| | | | | | Methane | | NMOC | |
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Black Ash	18	36	63.5	127	5.5	11	13.5	27
Modesto Ash	16	32	81.5	163	5	10	12	24
White Ash	21.5	43	57	113	6.5	13	16	32
Catalpa	8.5	17	44.5	89	2.5	5	6.5	13
Horse Chesnut	27	54	73.5	147	8	17	20	40
Cottonwood	19	38	45	90	6	12	14	28
American Elm	13	26	59.5	119	4	8	9.5	19
Eucalyptus	18	36	45	90	5.5	11	13.5	27
Sweet Gum	16.5	33	70	140	5	10	12.5	25
Black Locust	35	70	65	130	11	22	26	52
Magnolia	6.5	13	27.5	55	2	4	5	10
Silver Maple	33	66	51	102	10	20	24.5	49
American Sycamore	7.5	15	57.5	115	2.5	5	5.5	11
California Sycamore	5	10	52	104	1.5	3	3.5	7
Tulip	10	20	38.5	77	3	6	7.5	15
Red Oak	46	92	68.5	137	14	28	34	69
Sugar Maple	26.5	53	54	108	8	16	20	40
Unspecified	19	38	56	112	6	12	14	28

a   References 18 - 19. Factors are an aritmetic average of results obtained by burning high and low moisture content conical piles, ignited either at the top or around the periphery of the bottom. The windrow arrangement was only tested on Modesto Ash, Catalpa, American Elm, Sweet Gum, Silver Maple and Tulip Poplar, and results are included in the averages for these species.

b   The majority of particulate is submicron in size.

c   Tests indicate that VOC emissions average 29% methane, 11% other saturates, 33% olefins, 27% other (arjomatics, acetylene, oxygenates).

of refuse type and also, in certain instances, as a function of burning techniques and/or moisture content when these variables are known to significantly affect emissions. Table 2.4-5 also presents typical fuel loading values associated with each type of refuse. These values can be used, along with the corresponding emission factors, to estimate emissions from certain categories of agricultural burning when the specific fuel loadings for a given area are not known.

Emissions from leaf burning are dependent upon the moisture content, density, and ignition location of the leaf piles. Increasing the moisture content of the leaves generally increases the amount of carbon monoxide, hydrocarbon, and particulate emissions. Carbon monoxide emissions decreases if moisture content is high but increases if moisture content is low. Increasing the density of the piles increases the amount of hydrocarbon and particulate emissions, but has a variable effect on carbon monoxide emissions.

The highest emissions from open burning of leaves occur when the base of the leaf pile is ignited. The lowest emissions generally arise from igniting a single spot on the top of the pile. Particulate, hydrocarbon, and carbon monoxide emissions from window ignition (piling the leaves into a long row and igniting one end, allowing it to burn toward the other end) are intermediate between top and bottom ignition. Emission factors for leaf burning are presented in Table 2.4-6. For more detailed information on this subject, the reader should consult the reference cited at the end of this section.

Agricultural Plastic Film. Agricultural plastic film that has been used for ground moisture and weed control. Large quantities of plastic film are commonly disposed of when field crops are burned. The plastic film may also be gathered into large piles and burned separately or burned in an air curtain. Emissions from burning agricultural plastic are dependent on whether the film is new or has been exposed to vegetation and possibly pesticides. Table 2.4-7 presents emission factors for organic compounds emitted from burning new and used plastic film in piles or in piles where air has been forced through them to simulate combustion in an air curtain. Table 2.4-8 presents emission factors for PAH's emitted from open burning of inorganic plastic film.

Table 2.4-7
Emission Factors for Organic Compounds From Burning Plastic Film[a]
Emission Factor Rating: C

Pollutant	Units	Condition of plastic			
		Unused Plastic		Used Plastic	
		Pile[b]	Forced air[c]	Pile[b]	Forced air[c]
Benzene	(mg/kg plastic)	0.0478	0.0288	0.0123	0.0244
	(lb/1000 tons plastic)	0.0955	0.0575	0.0247	0.0488
Toluene	(mg/kg plastic)	0.0046	0.0081	0.0033	0.0124
	(lb/1000 tons plastic)	0.0092	0.0161	0.0066	0.0248
Ethyl benzene	(mg/kg plastic)	0.0006	0.0029	0.0012	0.0056
	(lb/1000 tons plastic)	0.0011	0.0058	0.0025	0.0111
1-Hexene	(mg/kg plastic)	0.0010	0.0148	0.0043	0.0220
	(lb/1000 tons plastic)	0.0020	0.0296	0.0086	0.0440

[a]Reference 22
[b]Emission factors are for plastic gathered in a pile and burned.
[c]Emission factors are for plastic burned in a pile with a forced air current.

Table 2.4-8

Polycyclic Aromatic Hydrocarbon Emission Factors from Open Burning of Agricultural Plastic Film[a]

Emission Factor Rating: C

Pollutant	Units	Condition of Plastic			
		Unused plastic		Used plastic	
		Pile[b]	Forced air[c]	Pile[b]	Forced Air[c,d]
Anthracene	(ug/kg plastic film)	7.14	0.66	1.32	0.40
	(lb/1000 tons plastic film)	0.0143	0.0013	0.0026	0.0008
Benzo(A)pyrene	(ug/kg plastic film)	41.76	1.45	7.53	0.00
	(lb/1000 tons plastic film)	0.0835	0.0029	0.0151	0.0000
Benzo(B)fluoranthene	(ug/kg plastic film)	34.63	1.59	9.25	0.93
	(lb/1000 tons plastic film)	0.0693	0.0032	0.0185	0.0019
Benzo(e)pyrene	(ug/kg plastic film)	32.38	1.45	9.65	0.00
	(lb/1000 tons plastic film)	0.0648	0.0029	0.0193	0.0000
Benzo(G,H,I)perylene	(ug/kg plastic film)	49.43	2.11	14.93	0.00
	(lb/1000 tons plastic film)	0.0989	0.0042	0.0299	0.0000
Benzo(K)fluoranthene	(ug/kg plastic film)	13.74	0.66	2.51	0.00
	(lb/1000 tons plastic film)	0.0275	0.0013	0.0050	0.0000
Benz(A)anthracene	(ug/kg plastic film)	52.73	2.91	14.41	1.19
	(lb/1000 tons plastic film)	0.1055	0.0058	0.0288	0.0024
Chrysene	(ug/kg plastic film)	54.98	3.70	17.18	1.19
	(lb/1000 tons plastic film)	0.1100	0.0074	0.0344	0.0024

Table 2.4-8 (Continued)

Pollutant	Units	Condition of Plastic			
		Unused plastic		Used plastic	
		Pile[b]	Forced air[c]	Pile[b]	Forced Air[c,d]
Fluoranthene	(ug/kg plastic film)	313.08	53.39	107.05	39.12
	(lb/1000 tons plastic film)	0.6262	0.1068	0.2141	0.0782
Indeno(1,2,3-CD)pyrene	(ug/kg plastic film)	40.04	2.78	10.70	0.00
	(lb/1000 tons plastic film)	0.0801	0.0056	0.0214	0.0000
Phenanthrene	(ug/kg plastic film)	60.40	12.56	24.05	8.72
	(lb/1000 tons plastic film)	0.1208	0.0251	0.0481	0.0174
Pyrene	(ug/kg plastic film)	203.26	18.24	58.81	5.95
	(lb/1000 tons plastic film)	0.4065	0.0365	0.1176	0.0119
Retene	(ug/kg plastic film)	32.38	2.91	18.77	3.04
	(lb/1000 tons plastic film)	0.0648	0.0058	0.0375	0.0061

[a]Reference 22.
[b]Emission factors are for plastic gathered in a pile and burned.
[c]Emission factors are for plastic burned in a pile with a forced air current.
[d]0.00 values indicate pollutant was not found.

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3.1 STATIONARY GAS TURBINES FOR ELECTRICITY GENERATION

3.1.1 General

Stationary gas turbines are applied in electric power generators, in gas pipeline pump and compressor drives, and in various process industries. Gas turbines (greater than 3 MW(e)) are used in electrical generation for continuous, peaking, or standby power. The primary fuels used are natural gas and distillate (No. 2) fuel oil, although residual fuel oil is used in a few applications.

3.1.2 Emissions

Emission control technologies for gas turbines have advanced to a point where all new and most existing units are complying with various levels of specified emission limits. For these sources, the emission factors become an operational specification rather than a parameter to be quantified by testing. This section treats uncontrolled (i.e., baseline) emissions and controlled emissions with specific control technologies.

The emission factors presented are for simple cycle gas turbines. These factors also apply to cogeneration/combined cycle gas turbines. In general, if the heat recovery steam generator (HRSG) is not supplementary fired, the simple cycle input specific emission factors (lbm/MMBtu) will apply to cogeneration/combined cycle systems. The output specific emissions (g/hp-hr) will decrease according to the ratio of simple cycle to combined cycle power output. If the HRSG is supplementary fired, the emissions and fuel usage must be considered to estimate stack emissions. Nitrogen Oxide (NO_x) emissions from regenerative cycle turbines (which account for only a small percentage of turbines in use) are greater than emissions from simple cycle turbines because of the increased combustion air temperature entering the turbine. The carbon monoxide (CO) and hydrocarbon (HC) emissions may be lower with the regenerative system for a comparable design. More power is produced from the same energy input, so the input specific emissions factor will be affected by changes in emissions, while output specific emissions will reflect the increased power output.

Water/steam injection is the most prevalent NOx control for cogeneration/combined cycle gas turbines. The water or steam is injected with the air and fuel into the turbine combustion can in order to lower the peak temperatures which, in turn, decreases the thermal NO_x produced. The lower average temperature within the combustor can may produce higher levels of CO and HC as a result of incomplete combustion.

Selective catalytic reduction (SCR) is a post-combustion control which selectively reduces NO_x by reaction of ammonia and NO on a catalytic surface to form N_2 and H_2O. Although SCR systems can be used alone, all existing applications of SCR have been used in conjunction with water/steam injection controls. For optimum SCR operation, the flue gas must be within a temperature range of 600-800°F with the precise limits dependant on the catalyst. Some SCR systems also utilize a CO catalyst to give simultaneous catalytic CO/NO_x control.

Advanced combustor can designs are currently being phased into production turbines. These dry techniques decrease turbine emissions by modifying the combustion mixing, air staging, and flame stabilization to allow operation at a much leaner air/fuel ratio relative to normal operation. Operating at leaner conditions will lower peak temperatures within the primary flame zone of the combustor. The lower temperatures may also increase CO and HC emissions.

With the proliferation and advancement of NO_x control technologies for gas turbines during the past 15 years, the emission factors for the installed gas turbine population are quite different than uncontrolled turbines. However, uncontrolled turbine emissions have not changed significantly. Therefore a careful review of specific turbine details should be performed before applying uncontrolled emission factors. Today most gas turbines are controlled to meet local, state, and/or federal regulations.

The average gaseous emission factors for uncontrolled gas turbines (firing natural gas and fuel oil) are presented in Tables 3.1-1 and 3.1-2. There is some variation in emissions over the population of large uncontrolled gas turbines because of the diversity of engine designs and models. Tables 3.1-3 and 3.1-4 present emission factors for gas turbines controlled for NO_x using water injection, steam injection or SCR. Tables 3.1-5 and 3.1-6 present emission factors for large distillate oil- fired turbines controlled for NO_x using water injection.

Gas turbines firing distillate or residual oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel should be used for flue gas emission factors assuming all metals pass through the turbine. If the fuel analysis is not known, Table 3.1-7 provides order of magnitude levels for turbines fired with distillate oil.

TABLE 3.1-5. (ENGLISH UNITS) EMISSION FACTORS FOR LARGE
DISTILLATE OIL-FIRED CONTROLLED GAS TURBINES[16]

Pollutant	Emission Factor Rating	Water Injection (.8 water/fuel ratio)	
		[grams/hr-hp][a] (power output)	[lb/MMBtu] (fuel input)
NO$_x$	E	1.05	.290
CO	E	.067	.0192
TOC (as methane)	E	.017	.0048
SOx	B	b	b
PM	E	.135	.0372

a.   Calculated from fuel input assuming an average heat rate of 8,000 Btu/hp-hr (x 3.632).
c.   All sulfur in the fuel is assumed to be converted to SO$_x$.

TABLE 3.1-6. (METRIC UNITS) EMISSION FACTORS FOR LARGE
DISTILLATE OIL-FIRED CONTROLLED GAS TURBINES[16]

Pollutant	Emission Factor Rating	Water Injection (.8 water/fuel ratio)	
		[grams/kW-hr][a] (power output)	[ng/J] (fuel input)
NO$_x$	E	1.41	125
CO	E	.090	8.26
TOC (as methane)	E	.023	2.06
SO$_x$[b]	B	b	b
PM	E	.181	16.00

a.   Calculated from fuel input assuming an average heat rate of 8,000 Btu/hp-hr (x 3.632).
b.   All sulfur in the fuel is assumed to be converted to SO$_x$.

TABLE 3.1-7. TRACE ELEMENT EMISSION FACTORS FOR DISTILLATE OIL-FIRED GAS TURBINES[1]
(Emission Factor Rating: E)[a]

Trace Element	pg/J	lb/MMBtu
Aluminum	64	1.5 E-04
Antimony	9.4	2.2 E-05
Arsenic	2.1	4.9 E-06
Barium	8.4	2.0 E-05
Beryllium	.14	3.3 E-07
Boron	28	6.5 E-05
Bromine	1.8	4.2 E-06
Cadmium	1.8	4.2 E-06
Calcium	330	7.7 E-04
Chromium	20	4.7 E-05
Cobalt	3.9	9.1 E-06
Cooper	578	1.3 E-03
Iron	256	6.0 E-04
Lead	25	5.8 E-05
Magnesium	100	2.3 E-04
Manganese	145	3.4 E-04
Mercury	.39	9.1 E-07
Molybdenum	3.6	8.4 E-06
Nickel	526	1.2 E-03
Phosphorus	127	3.0 E-04
Potassium	185	4.3 E-04
Selenium	2.3	5.3 E-06
Silicon	575	1.3 E-03
Sodium	590	1.4 E-03
Tin	35	8.1 E-05
Vanadium	1.9	4.4 E-06
Zinc	294	6.8 E-04

a.   Emission factor ratings of "E" indicate that the data are from a limited data set
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TABLE 3.1-1. (ENGLISH UNITS)
EMISSION FACTORS FOR LARGE UNCONTROLLED GAS TURBINES[1-8]

Pollutant	Emission Factor Rating[a]	Natural Gas (SCC-2-01-002-01)		Fuel Oil (i.e. Distillate) (SCC-2-01-001-01)	
		[grams/hr-hp][b] (power output)	[lb/MMBtu] (fuel input)	[grams/hp-hr][b] (power output)	[lb/MMBtu] (fuel input)
NO_x	C	1.6	.44	2.54	.698
CO	D	.39	.11	.174	.048
CO_2[c]	B	407	112	596	164
TOC (as methane)	D	.087	.024	.062	.017
SOx (as SO_2)	B	d	d	d	d
PM (solids)	E	.070	.0193	.138	.038
PM (condensables)	E	.082	.0226	.084	.023
PM Sizing % < .05 microns	D		15%		16%
< .10 microns	D		40%		48%
< .15 microns	D		63%		72%
< .20 microns	D		78%		85%
< .25 microns	D		89%		93%
< 1 micron	D		100%		100%

a. "D" and "E" rated emission factors are due to limited data and/or a lack of documentation of test results. "D" and "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

b. Calculated from lb/MMBtu assuming an average heat rate of 8,000 Btu/hp-hr (x 3.632).

c. Based on 100 percent conversion of the fuel carbon to CO_2. CO_2[lb/MMBtu] = 3.67*C/E, where C = carbon content of fuel by weight, .7, and E = energy content of fuel, .0023 MMBtu/lb. The uncontrolled CO_2 emission factors are also applicable to controlled gas turbines.

d. All sulfur in the fuel is converted to SO_2.

Uncontrolled Emission Factors	Emission factor Rating[a]	Natural Gas (SCC-2-01-002-01)		Fuel Oil (i.e. Distillate) (SCC-2-01-00-01)	
		[grams/kW-hr[b] (power output)	[ng/J] (fuel input)	[grams/kW-hr][b] (power output)	[ng/J] (fuel input)
NO_x	C	2.15	190	3.41	300
CO	D	.52	46	.233	20.6
CO_2[c]	B	546	48160	799	70520
TOC (as methane)	D	.117	10.32	.083	7.31
SOx (as SO_2)	B	d	d	d	d
PM (solids)	E	.094	8.30	.185	16.3
PM (condensables)	E	.11	9.72	.113	9.89
PM Sizing %					
< .05 microns	D		15%		16%
< .10 microns	D		40%		48%
< .15 microns	D		63%		72%
< .20 microns	D		78%		85%
< .25 microns	D		89%		93%
< 1 micron	D		100%		100%

a. "D" and "E" rated emission factors are due to limited data and/or a lack of documentation of test results. "D" and "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

b. Calculated from ng/J assuming an average heat rate of 11,318 KJ/KW-hr.

c. Based on 100 percent conversion of the fuel carbon to CO_2. CO_2[lb/MMBtu] = 3.67*C/E, where C = ratio of carbon in the fuel by weight, and E = energy content of fuel, MMBtu/lb. The uncontrolled CO_2 emission factors are also applicable to controlled gas turbines.

d. All sulfur in the fuel is assumed to be converted to SO_2.

Controlled Emission Factors Fuel: Natural Gas	Water Injection (.8 water/fuel ratio)		Steam Injection (1.2 water/fuel ratio)		Selective Catalytic Reduction (with water injection)
	[grams/hr-hp] (power output)	[lb/MMBtu] (fuel input)	[grams/hr-hp] (power output)	[lb/MMBtu] (fuel input)	[lb/MMBtu] (fuel input)
NO_x	.50	.14	.44	.12	.03[b]
CO	.94	.28	.53	.16	.0084
TOC (as methane)					.014
NH_3					.0065
NMHC					.0032
Formaldehyde					.0027

a.　All data are averages of a limited number of tests and may not be typical of those reductions which can be achieved at a specific location.

b.　Average of 78 percent reduction of NO_x through the SCR catalyst.

TABLE 3.1-4. (METRIC UNITS)
EMISSION FACTORS FOR LARGE GAS-FIRED CONTROLLED GAS TURBINES[3,10-15]
(Emission Factor Rating: C)

Controlled Emission Factors Fuel: Natural Gas	Water Injection (.8 water/fuel ratio)		Steam Injection (1.2 water/fuel ratio)		Selective Catalytic Reduction (with water injection)
	[grams/kW-hr] (power output)	[ng/J] (fuel input)	[grams/kW-hr] (power output)	[ng/J] (fuel input)	[ng/J] (fuel input)
NO$_x$	.66	61	.59	52	3.78[b]
CO	1.3	120	.71	69	3.61
TOC (as methane)					6.02
NH$_3$					2.80
NMHC					1.38
Formaldehyde					1.16

a.   All data are averages of a limited number of tests and may not be typical of those reductions which can be achieved at a specific location.

b.   Average of 78 percent reduction of NO$_x$ through the SCR catalyst.

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3.2 HEAVY DUTY NATURAL GAS FIRED PIPELINE COMPRESSOR ENGINES

3.2.1 General

Engines in the natural gas industry are used primarily to power compressors used for pipeline transportation, field gathering (collecting gas from wells), underground storage, and gas processing plant applications, i.e. prime movers. Pipeline engines are concentrated in the major gas producing states (such as those along the Gulf Coast) and along the major gas pipelines. Gas turbines emit considerably smaller amounts of pollutants than do reciprocating engines; however, reciprocating engines are generally more efficient in their use of fuel.

Reciprocating engines are separated into three design classes: 2-stroke lean burn, 4-stroke lean burn and 4-stroke rich burn. Each of these have design differences which affect both baseline emissions as well as the potential for emissions control. Two-stroke engines complete the power cycle in a single engine revolution compared to two revolutions for 4-stroke engines. With the two-stroke engine, the fuel/air charge is injected with the piston near the bottom of the power stroke. The valves are all covered or closed and the piston moves to the top of the cylinder compressing the charge. Following ignition and combustion, the power stroke starts with he downward movement of the piston. Exhaust ports or valves are then uncovered to remove the combustion products, and a new fuel/air charge is ingested. Two stroke engines may be turbocharged using an exhaust powered turbine to pressurize the charge for injection into the cylinder. Non-turbocharged engines may be either blower scavenged or piston scavenged to improve removal of combustion products.

Four stroke engines use a separate engine revolution for the intake/compression stroke and the power/exhaust stroke. These engines may be either naturally aspirated, using the suction from the piston to entrain the air charge, or turbocharged, using a turbine to pressurize the charge. Turbocharged units produce a higher power output for a given engine displacement, whereas naturally aspirated units have lower initial cost and maintenance. Rich burn engines operate near the fuel-air stoichiometric limit with exhaust excess oxygen levels less than 4 percent. Lean burn engines may operate up to the lean flame extinction limit, with exhaust oxygen levels of 12 percent or greater. Pipeline population statistics show a nearly equal installed capacity of turbines and reciprocating engines. For reciprocating engines, two stroke designs contribute approximately two-thirds of installed capacity.

3.2.2 Emissions and Controls

The primary pollutant of concern is NO_x, which readily forms in the high temperature, pressure, and excess air environment found in natural gas fired compressor engines. Lesser amounts of carbon monoxide and hydrocarbons are emitted, although for each unit of natural gas burned, compressor engines (particularly reciprocating engines) emit significantly more of these pollutants than do external combustion boilers. Sulfur oxides emissions are proportional to the sulfur content of the fuel and will usually be quite low because of the negligible sulfur content of most pipeline gas. This section will also discuss the major variables affecting NO_x emissions and the various control technologies that will reduce uncontrolled NO_x emissions.

The major variables affecting NO_x emissions from compressor engines include the air fuel ratio, engine load (defined as the ratio of the operating horsepower to the rated horsepower), intake (manifold) air temperature and absolute humidity. In general, NO_x emissions increase with increasing load and intake air temperature and decrease with increasing absolute humidity and air fuel ratio. (the latter already being,

in most compressor engines, on the "lean" side of that air fuel ratio at which maximum NO_x formation occurs). Quantitative estimates of the effects of these variables are presented in Reference 10.

Because NO_x is the primary pollutant of significance emitted from pipeline compressor engines, control measures to date have been directed mainly at limiting NO_x emissions. Reference 11 summarizes control techniques and emission reduction efficiencies. For gas turbines, the early control applications used water or steam injection. New applications of dry low NO_x combustor can designs and selective catalytic reduction are appearing. Water injection has achieved reductions of 70 to 80 percent with utility gas turbines. Efficiency penalties of 2 to 3 percent are typical due to the added heat load of the water. Turbine power outputs typically increase, however. Steam injection may also be used, but the resulting NO_x reductions may not be as great as with water injection, and it has the added disadvantage that a supply of steam must be readily available. Water injection has not been applied to pipeline compressor engines because of the lack of water availability.

The efficiency penalty and operational impacts associated with water injection have led manufacturers to develop dry low NO_x combustor can designs based on lean burn and/or staging to suppress NO_x formation. These are entering the market in the early 1990's. Stringent gas turbine NO_x limits have been achieved in California in the late 1980's with selective catalytic reduction. This is an ammonia based post-combustion technology which can achieve in excess of 80 percent NO_x reductions. Water or steam injection is frequently used in combination with SCR to minimize ammonia costs.

For reciprocating engines, both combustion controls and post-combustion catalytic reduction have been developed. Controlled rich burn engines have mostly been equipped with non-selective catalytic reduction which uses unreacted hydrocarbons and CO to reduce NO_x by 80 to 90 percent. Some rich-burn engines can be equipped with prestratified charge which reduces the peak flame temperature in the NO_x forming regions. Lean burn engines have mostly met NO_x reduction requirements with lean combustion controls using torch ignition or chamber redesign to enhance flame stability. NO_x reductions of 70 to 80 percent are typical for numerous engines with retrofit or new unit controls. Lean burn engines may also be controlled with SCR, but the operational problems associated with engine control under low NO_x operation have been a deterrent.

Emission factors for natural gas fired pipeline compressor engines are presented in Tables 3.2-1 and 3.2-2 for baseline operation and in 3.2-4 through 3.2-7 for controlled operation. The factors for controlled operation are taken from a single source test. Table 3.2-3 lists non-criteria (organic) emission factors.

TABLE 3.2-1. (ENGLISH UNITS) CRITERIA EMISSION FACTORS FOR UNCONTROLLED NATURAL GAS PRIME MOVERS[a]

Pollutant [Rating]	Gas Turbines SCC: 2-02-002-01		2-Cycle Lean Burn SCC: 2-02-002-02		4-Cycle Lean Burn SCC: 2-02-002-02		4-Cycle Rich Burn SCC: 2-02-002-02,	
	[grams/hp-hr]	[lb/MMBtu] (fuel input)	[grams/hp-hr]	[lb/MMBtu] (fuel input)	[grams/hp-hr]	[lb/MMBtu] (fuel input)	[grams/hp-hr]	[lb/MMBtu] (fuel input)
NOx [A]	1.3	.34	11	2.7	12	3.2	10	2.3
CO [A]	.83	.17	1.5	.38	1.6	.42	8.6	1.6
CO$_2$ [B][b]	405	110	405	110	405	110	405	110
TOC [A]	.18	.053	6.1	1.5	4.9	1.2	1.2	.27
TNMOC [A]	.01	.002	.43	.11	.72	.18	.14	.03
CH$_4$ [A]	.17	.051	5.6	1.4	4.1	1.1	1.1	.24

a. Emission factors based on data from references 1 (population info.) and 2 (emissions data); Emission factors are based on entire population. Emission factors for individual engines from specific manufacturers may vary.

b. Based on 100 percent conversion of the fuel carbon to CO$_2$. CO$_2$[lb/MMBtu] = 3.67*C/E, where C = carbon content of fuel by weight, .7, and E = energy content of fuel, .0023 MMBtu/lb. The uncontrolled CO$_2$ emission factors are also applicable to natural gas prime movers controlled by combustion modifications, NSCR and SCR.

TABLE 3.2-2. (METRIC UNITS) CRITERIA EMISSION FACTORS FOR UNCONTROLLED NATURAL GAS PRIME MOVERS[a]

Pollutant [Rating]	Gas Turbines SCC: 2-02-002-01		2-Cycle Lean Burn SCC: 2-02-002-02		4-Cycle Lean Burn SCC: 2-02-002-02		4-Cycle Rich Burn SCC: 02-002-02	
	[grams/ kW-hr]	[ng/J] (fuel input)	[grams/ kW-hr]	[ng/J] (fuel input)	[grams/ kW-hr]	[ng/J] (fuel input)	[grams/ kW-hr]	[ng/J] (fuel input)
NO_x [A]	1.70	145	14.79	1165	15.49	1286	13.46	980
CO [A]	1.11	71	2.04	165	10.29	1195	11.55	697
CO_2 [D][b]	741	47,424	741	47,424	741	47,424	741	47,424
TOC [A]	.24	22.8	8.14	662	5.50	447	1.66	116
TNMOC [A]	.013	.86	.58	47.3	.76	60.2	.19	12.9
CH_4 [A]	.228	21.9	7.56	615	4.73	387	1.48	103

a.   Emission Factors based on data from References 1 (population info.) and 2 (emissions data); Emission factors are based on entire population. Emission factors for individual engines from specific manufacturers may vary.

b.   Based on 100 percent conversion of the fuel carbon to CO_2. $CO_2[lb/MMBtu] = 3.67*C/E$, where C = carbon content of fuel by weight, .7, and E = energy content of fuel, .0023 MMBtu/lb. The uncontrolled CO_2 emission factors are also applicable to natural gas prime movers controlled by combustion modifications, NSCR and SCR.

TABLE 3.2-3. (ENGLISH AND METRIC UNITS) NON-CRITERIA EMISSION FACTORS FOR UNCONTROLLED NATURAL GAS PRIME MOVERS[3-5]
(Emission Factor Rating: E)[a]

Pollutant	2-Cyc Lean	
	[grams/kw-hr]	[ng/J]
Formaldehyde	1.78	140
Benzene	2.2E-3	0.17
Toluene	2.2E-3	0.17
Ethylbenzene	1.1E-3	0.086
Xylenes	3.3E-3	0.26

a.   All emission factor qualities are "E" are due to a very limited data set. "E" rated emission factors may not be applicable to specific facilities or populations.

TABLE 3.2-4. (ENGLISH AND METRIC UNITS) EMISSION FACTORS FOR CONTROLLED NATURAL GAS PRIME MOVERS: COMBUSTION MODIFICATIONS ON TWO-STROKE LEAN BURN ENGINE[6]

(Emission Factor Rating: E)[a]

Pollutant	Baseline				Increased A/F Ratio With Intercooling			
	[g/hp-hr]	[lb/1E6Btu]	[g/kW-hr]	[ng/J]	[g/hp-hr]	[g/kW-hr]	[lb/1E6Btu]	[ng/J]
NOx	9.9	2.9	13	1300	5.1	6.8	1.5	650
CO	.94	.28	1.3	120	1.5	2.1	.46	200
TOC	7.5	2.2	10	960	8.5	11	2.6	1100
TNMOC	5.2	1.6	7.0	670	6.0	8.1	1.8	780
CH$_4$	2.3	.68	3.1	290	2.5	3.4	.75	320
PM (total = front+back)	.16	.046	.21	20	.18	.25	.055	24
(solids = front half)	.098	.029	.13	13	.13	.17	.038	16
(condensibles = back half)	.057	.017	.076	7.3	.058	.078	.017	7.3

a. All emission factor qualities are "E" due to a very limited data set. "E" rated emission factors may not be applicable to specific facilities or populations.

TABLE 3.2-5. (ENGLISH AND METRIC UNITS) EMISSION FACTORS FOR CONTROLLED NATURAL GAS PRIME MOVERS: NSCR ON FOUR-CYCLE RICH BURN ENGINE[3-5,7]

(Emission Factor Rating: E)[a]

Pollutant	Inlet				Outlet			
	[g/hp-hr]	[g/kW-hr]	[lb/1E6Btu]	[ng/J]	[g/hp-hr]	[g/kW-hr]	[lb/1E6Btu]	[ng/J]
NOx	7.8	10	1.8	770	2.5	3.4	.58	250
CO	12	16	2.8	1208	10	14	2.4	1000
TOC	.33	.44	.079	33.97	.2	.27	.047	20
NH$_3$	.05	.07	.012	5.16	.82	1.10	.19	82
C7 -> C16	.019	.026	.0042	1.81	.0041	.0055	.0009	.39
C16+	.017	.029	.004	1.72	.0006	.0008	.0001	.043
PM (solids = front half)	.003	.004	.0007	.301	.003	.004	.0007	.30
Benzene			7.1EE4	.31			1.1E-4	.047
Toluene			2.3EE4	.099			<2.3E-5	.0099
Xylenes			<5.9E-5	.025			<4E-5	.017
Propylene			<1.6E-4	.069			<1.6E-4	.069
Naphthalene			<4.9E-5	.021			<4.9E-5	.021
Formaldehyde			<1.6E-3	.69			<7.2E-6	.003
Acetaldehyde			<6.1E-5	.026			<4.8E-6	.0021
Acrolein			<3.7E-5	.016			<9.6E-6	.0041

a.   All emission factors are rated "E" due to a very limited data set. "E" rated emission factors may not be applicable to specific facilities or populations.

TABLE 3.2-6. (ENGLISH AND METRIC UNITS) EMISSION FACTORS FOR CONTROLLED NATURAL GAS PRIME MOVERS: SCR ON FOUR-CYCLE LEAN BURN ENGINE[8]

(Emission Factor Rating: E)[a]

Pollutant	Inlet				Outlet			
	[g/hp-hr]	[g/kW-hr]	[lb/1E6Btu]	[ng/J]	[g/hp-hr]	[g/kW-hr]	[lb/1E6Btu]	[ng/J]
NOx	19	26	6.4	2800	3.6	4.8	1.2	510
CO	1.2	1.6	.38	160	1.1	1.5	.37	160
NH₃					.27	.36	.091	39
C7 -> C16	.007	.009	.0023	.99	.0031	.0042	.0013	.56
C16+	.013	.017	.0044	1.9	.0024	.0032	.0008	.34

a. All emission factor qualities are "E" due to a very limited data set. "E" rated emission factors may not be applicable to specific facilities or populations.

TABLE 3.2-7 (ENGLISH AND METRIC UNITS) EMISSION FACTORS FOR CONTROLLED NATURAL GAS PRIME MOVERS: "PCC" AND "CLEAN BURN" ON TAWO-CYCLE LEAN BURN ENGINE[10]

(Emission Factor Rating: C)

Pollutant	"CleanBurn"				"PreCombustion Chamber"			
	[g/hp-hr]	[g/kW-hr]	[lb/1E6*Btu]	[ng/J]	[g/hp-hr]	[g/kW-hr]	[lb/1E6*Btu]	[ng/J]
NOx	2.3	3.1	.83	360	2.9	3.9	.85	370
CO	1.1	1.5	.30	130	2.4	3.3	.67	290
TOC	2.5	3.4	.77	330	6.4	8.6	1.8	760
TNMOC	.12	.16	.15	65	.88	1.2	.25	110
CH₄	2.4	3.3	.62	260	5.5	7.4	1.5	650

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3.3 GASOLINE AND DIESEL INDUSTRIAL ENGINES

3.3.1 General

The engine category addressed by this section covers a wide variety of industrial applications of both gasoline and diesel internal combustion engines such as, aerial lifts, fork lifts, mobile refrigeration units, generators, pumps, industrial sweepers/scrubbers, material handling equipment (such as conveyors), and portable well-drilling equipment. The rated power of these engines covers a rather substantial range; up to 186 kW (250 hp) for gasoline engines and up to 447 kW (600 hp) for diesel engines. (Diesel engines greater than 600 hp are covered in Section 3.4: Large Stationary Diesel and All Stationary Dual Fuel Engines). Understandably, substantial differences in engine duty cycles exist. It was necessary, therefore, to make reasonable assumptions concerning usage in order to formulate some of the emission factors.

3.3.2 Process Description

All reciprocating internal combustion (IC) engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are two methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). Section 3.3 deals with both types of reciprocating internal combustion engines.

In compression ignition engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous as the air is above the auto-ignition temperature of the fuel. Spark ignition engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder. All diesel fueled engines are compression ignited and all gasoline fueled engines are spark ignited.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature auto-ignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.

3.3.3 Emissions and Controls

The best method for calculating emissions is on the basis of "brake specific" emission factors (g/hp-hr or g/kW-hr). Emissions are calculated by taking the product of the brake specific emission factor, the usage in hours (that is, hours per year or hours per day), the power available (rated power), and the load factor (the power actually used divided by the power available).

Once reasonable usage and duty cycles for this category were ascertained, emission values were aggregated to arrive at the factors presented in Tables 3.3-1 (English units) and 3.3-2 (Metric units) for criteria and organic pollutants. Emissions data for a specific design type were weighted according to estimated material share for industrial engines. The emission factors in this table are most appropriately applied to a population of industrial engines rather than to an individual power plant because of their aggregate nature. Table 3.3-3 shows unweighted speciated organic compound and air toxic emissions factors based upon only two engines. Their inclusion in this section is intended only for rough order of magnitude estimates.

Table 3.3-4 shows a summary of various diesel emission reduction technologies (some which may be applicable to gasoline engines). These technologies are categorized into fuel modifications, engine modifications, and exhaust after treatments. Current data are insufficient to quantify the results of the modifications. Table 3.3-4 provides general information on the trends of changes on selected parameters.

TABLE 3.3-1. (ENGLISH UNITS) EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]

Pollutant [Rating][b]	Gasoline Fuel SCC 20200301, 20300301		Diesel Fuel SCC 20200102, 20300101	
	[grams/hp-hr] (power output)	[lb/MMBtu] (fuel input)	[grams/hp-hr] (power output)	[lb/MMBtu] (fuel input)
NO_x [D]	5.16	1.63	14.0	4.41
CO [D]	199	62.7	3.03	0.95
SO_x [D]	0.268	0.084	0.931	0.29
Particulate [D]	0.327	0.10	1.00	0.31
CO_2 [B][c]	493	155	525	165
Aldehydes [D]	0.22	0.07	0.21	0.07
Hydrocarbons				
Exhaust [D]	6.68	2.10	1.12	0.35
Evaporative [E]	0.30	0.09	0.00	0.00
Crankcase [E]	2.20	0.69	0.02	0.01
Refueling [E]	0.49	0.15	0.00	0.00

a.   Data based on uncontrolled levels for each fuel from references 1, 3 and 6. When necessary, the average brake specific fuel consumption (BSFC) value was used to convert from g/hp-hr to lb/MMBtu was 7000 Btu/hp-hr.

b.   "D" and "E" rated emission factors are most appropriate when applied to a population of industrial engines rather than to an individual power plant, due to the aggregate nature of the emissions data.

c.   Based on assumed 100 percent conversion of carbon in fuel to CO_2 with 87 weight percent carbon in diesel, 86 weight percent carbon in gasoline, average brake specific fuel consumption of 7000 Btu/hp-hr, diesel heating value of 19300 Btu/lb, and gasoline heating value of 20300 Btu/lb.

TABLE 3.3-2. (METRIC UNITS) EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]

Pollutant [Rating][b]	Gasoline Fuel SCC 20200301, 20300301		Diesel Fuel SCC 20200102, 20300101	
	[grams/kW-hr] (power output)	[n/J] (fuel input)	[grams/kW-hr] (power output)	[n/J] (fuel input)
NO$_x$ [D]	6.92	699	18.8	1,896
CO [D]	267	26,947	4.06	410
SO$_x$ [D]	0.359	36	1.25	126
Particulate [D]	0.439	44	1.34	135
CO$_2$ [B][c]	661	66,787	704	71,065
Aldehydes [D]	0.30	29	0.28	28
Hydrocarbons				
Exhaust [D]	8.96	905	1.50	152
Evaporative [E]	0.40	41	0.00	0.00
Crankcase [E]	2.95	298	0.03	2.71
Refueling [E]	0.66	66	0.00	0.00

a.   Data based on uncontrolled levels for each fuel from references 1, 3 and 6.

b.   "D" and "E" rated emission factors are most appropriate when applied to a population of industrial engines rather than to an individual power plant, due to the aggregate nature of the emissions data.

c.   Based on assumed 100 percent conversion of carbon in fuel to CO_2 with 87 weight percent carbon in diesel, 86 weight percent carbon in gasoline, average brake specific fuel consumption of 7000 Btu/hp-hr, diesel heating value of 19300 Btu/lb, and gasoline heating value of 20300 Btu/lb.

TABLE 3.3-3. (ENGLISH AND METRIC UNITS) SPECIATED ORGANIC COMPOUNDS AND AIR TOXIC EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]
(All Emission Factors are Rated: E)[b]

Pollutant	[lb/MMBtu] (fuel input)	[n/J] (fuel input)
Benzene	9.33 E-04	0.401
Toluene	4.09 E-04	0.176
Xylenes	2.85 E-04	0.122
Propylene	2.58 E-03	1.109
1,3 Butadiene[c]	< 3.91 E-05	< 0.017
Formaldehyde	1.18 E-03	0.509
Acetaldehyde	7.67 E-04	0.330
Acrolein	< 9.25 E-05	< 0.040
Polycyclic Aromatic Hydrocarbons (PAH)		
Naphthalene	8.48 E-05	3.64 E-02
Acenaphthylene	< 5.06 E-06	< 2.17 E-03
Acenaphthene	< 1.42 E-06	< 6.11 E-04
Fluorene	2.92 E-05	1.26 E-02
Phenanthrene	2.94 E-05	1.26 E-02
Anthracene	1.87 E-06	8.02 0E-04
Fluoranthene	7.61 E-06	3.27 E-03
Pyrene	4.78 E-06	2.06 E-03
Benz(a)anthracene	1.68 E-06	7.21 E-04
Chrysene	3.53 E-07	1.52 E-04
Benzo(b)fluoranthene	< 9.91 E-08	< 4.26 E-05
Benzo(k)fluoranthene	< 1.55 E-07	< 6.67 E-05
Benzo(a)pyrene	< 1.88 E-07	< 8.07 E-05
Indeno(1,2,3-cd)pyrene	< 3.75 E-07	< 1.61 E-04
Dibenz(a,h)anthracene	< 5.83 E-07	< 2.50 E-04
Benzo(g,h,l)perylene	< 4.89 E-07	< 2.10 E-04
Total PAH	1.68 E-04	7.22 E-02

a. Data are based on the uncontrolled levels of two diesel engines from references 6 and 7.
b. "E" rated emission factors are due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.
c. Data are based on one engine.

TABLE 3.3-4. DIESEL EMISSION CONTROL TECHNOLOGIES[4]

Technology	Affected Parameter[a]	
	Increase	Decrease
Fuel Modifications		
Sulfur Content Increase	PM, Wear	
Aromatic Content Increase	PM, NO_x	
Cetane Number		PM, NO_x
10 percent and 90 percent Boiling Point		PM
Fuel Additives		PM, NO_x
Water/Fuel Emulsions		NO_x
Engine Modifications		
Injection Timing	NO_x, PM, BSFC, Power	NO_x
Fuel Injection Pressure	PM, NO_x	
Injection Rate Control		NO_x, PM
Rapid Spill Nozzles		PM
Electronic Timing & Metering		NO_x, PM
Injector Nozzle Geometry		PM
Combustion Chamber Modifications		NO_x, PM
Turbocharging	PM, Power	NO_x
Charge Cooling		NO_x
Exhaust Gas Recirculation	PM, Power, Wear	NO_x
Oil Consumption Control		PM, Wear
Exhaust After Treatment		
Particulate Traps		PM
Selective Catalytic Reduction		NO_x
Oxidation Catalysts		HC, CO, PM

a. NO_x = Nitrogen oxides; PM = Particulate matter; HC = Hydrocarbons; CO = Carbon monoxide; BSFC = Brake specific fuel consumption.

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3.4 LARGE STATIONARY DIESEL AND ALL STATIONARY DUAL FUEL ENGINES

3.4.1 General

The primary domestic use of large stationary diesel engines (greater than 600 hp) is in oil and gas exploration and production. These engines, in groups of three to five, supply mechanical power to operate drilling (rotary table), mud pumping and hoisting equipment, and may also operate pumps or auxiliary power generators. Another frequent application of large stationary diesels is electricity generation for both base and standby service. Smaller uses include irrigation, hoisting and nuclear power plant emergency cooling water pump operation.

Dual fuel engines were developed to obtain compression ignition performance and the economy of natural gas, using a minimum of 5 to 6 percent diesel fuel to ignite the natural gas. Large dual fuel engines have been used almost exclusively for prime electric power generation. This section includes all dual fuel engines.

3.4.2 Process Description

All reciprocating internal combustion (IC) engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are two methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). Section 3.4 deals only with compression ignition engines.

In compression ignition engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous as the air is above the auto-ignition temperature of the fuel. Spark ignition engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder. Although all diesel fueled engines are compression ignited and all gasoline and gas fueled engines are spark ignited, gas can be used in a compression ignition engine if a small amount of diesel fuel is injected into the compressed gas/air mixture to burn any mixture ratio of gas and diesel oil (hence the name dual fuel), from 6- to 100-percent diesel oil.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature auto-ignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.

3.4.3 Emissions and Controls

Most of the pollutants from IC engines are emitted through the exhaust. However, some hydrocarbons escape from the crankcase as a result of blowby (gases which are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Nearly all of the hydrocarbons from diesel (CI) engines enter the atmosphere from the exhaust. Crankcase blowby is minor because hydrocarbons are not present during compression of the charge. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels. In general, evaporative losses are also negligible in engines using gaseous fuels because these engines receive their fuel continuously from a pipe rather than via a fuel storage tank and fuel pump.

The primary pollutants from internal combustion engines are oxides of nitrogen (NO_x), organic compounds (hydrocarbons), carbon monoxide (CO), and particulates, which include both visible (smoke) and nonvisible emissions. The other pollutants are primarily the result of incomplete combustion. Ash and metallic additives in the fuel also contribute to the particulate content of the exhaust. Oxides of sulfur (SO_x) also appears in the exhaust from IC engines.

The primary pollutant of concern from large stationary diesel and all stationary dual fuel engines is NO_x, which readily forms in the high temperature, pressure, nitrogen content of the fuel, and excess air environment found in these engines. Lesser amounts of CO and hydrocarbons are emitted. The sulfur compounds, mainly SO_2, are directly related to the sulfur content of the fuel. SO_x emissions will usually be quite low because of the negligible sulfur content of diesel fuels and natural gas.

Tables 3.4-1 (English units) and 3.4-2 (Metric units) contain gaseous emission factors.

Table 3.4-3 shows the speciated organic compound emission factors and Table 3.4-4 shows the emission factors for polycyclic aromatic hydrocarbons (PAH). These tables do not provide a complete speciated organic compound and PAH listing since they are based only on a single engine test; they are to be used for rough order of magnitude comparisons.

Table 3.4-5 shows the particulate and particle sizing emission factors.

Control measures to date have been directed mainly at limiting NO_x emissions because NO_x is the primary pollutant from diesel and dual fuel engines. Table 3.4-6 shows the NO_x reduction and fuel consumption penalties for diesel and dual fueled engines based on some of the available control techniques. All of these controls are engine control techniques except for the selective catalytic reduction (SCR) technique, which is a post-combustion control. The emission reductions shown are those which have been demonstrated. The effectiveness of controls on an particular engine will depend on the specific design of each engine and the effectiveness of each technique could vary considerably. Other NO_x control techniques exist but are not included in Table 3.4-6. These techniques include internal/external exhaust gas recirculation (EGR), combustion chamber modification, manifold air cooling, and turbocharging.

TABLE 3.4-1. (ENGLISH UNITS) GASEOUS EMISSION FACTORS FOR LARGE STATIONARY DIESEL AND ALL STATIONARY DUAL FUEL ENGINES[a]

Pollutant	Diesel Fuel SCC 20200401			Dual Fuel SCC 20200402		
	[grams/hp-hr] (power output)	[lb/MMBtu] (fuel input)	Emission Factor Rating[b]	[grams/hp-hr] (power output)	[lb/MMBtu] (fuel input)	Emission Factor Rating[b]
NO_x	11	3.1	C	9.2	3.1	D
CO	2.4	0.81	C	2.3	0.79	D
SO_x	e	e	B	e	e	B
CO_2[g]	524	165	B	350	110	B
TOC[c] (as CH_4)	0.32	0.09	C	2.4	0.8	D
Methane	0.03	0.01	E[d]	1.8	0.6	E[f]
Nonmethane	0.33	0.10	E[d]	0.6	0.2	E[f]

a. Data are based on uncontrolled levels for each fuel from references 4, 5, and 6. When necessary, the average heating value of diesel was assumed to be 19300 Btu/lb with a density of 7.1 lb/gal. The power output and fuel input values were averaged independently from each other due to the use of actual Brake Specific Fuel Consumption values for each data point and the use of data that may have enough information to calculate only one of the two emission factors (e.g., if there was enough information to calculate lb/MMBtu, but not enough to calculate the g/hp-hr). The emission factors are based on averages across all manufacturers and duty cycles. The actual emissions from a particular engine or manufacturer could vary considerably from these levels.

b. "D" and "E" rating for emission factors are due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "D" and "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

c. Total Organic Compounds.

d. Based on emissions data from one engine.

e. Emissions should be estimated based on the assumption that all sulfur in the fuel is converted to SO_2.

f. Based on the assumption that nonmethane organic compounds are 25 percent of TOC emissions from dual fuel engines. Molecular weight of nonmethane gas stream is assumed to be that of methane.

g. Based on assumed 100 percent conversion of carbon in fuel to CO_2 with 87 weight percent carbon in diesel, 70 weight percent carbon in natural gas, dual fuel mixture of 5 percent diesel with 95 percent natural gas, average brake specific fuel consumption of 7000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and natural gas heating value of 23,900 Btu/lb.

TABLE 3.4-2. (METRIC UNITS) GASEOUS EMISSION FACTORS FOR LARGE STATIONARY DIESEL AND ALL STATIONARY DUAL FUEL ENGINES[a]

Pollutant	Diesel Fuel SCC 20200401			Dual Fuel SCC 20200402		
	[g/kW-hr] (power output)	[ng/J] (fuel input)	Emission Factor Rating[b]	[g/kW-hr] (power output)	[ng/J] (fuel input)	Emission Factor Rating[b]
NO_x	14	1,322	C	12.3	1,331	D
CO	3.2	349	C	3.1	340	D
SO_x	e	e	B	e	e	B
CO_2[g]	703	70,942	B	469	47,424	B
TOC[c] (as CH_4)	0.43	38	C	3.2	352	D
Methane	0.04	4	E[d]	2.4	240	E[f]
Nonmethane	0.44	45	E[d]	0.8	80	E[f]

a. Data are based on uncontrolled levels for each fuel from references 4, 5, and 6. When necessary, the average heating value of diesel was assumed to be 19300 Btu/lb with a density of 7.1 lb/gal. The power output and fuel input values were averaged independently from each other due to the use of actual Brake Specific Fuel Consumption values for each data point and the use of data that may have enough information to calculate only one of the two emission factors (e.g., if there was enough information to calculate lb/MMBtu, but not enough to calculate the g/hp-hr). The emission factors are based on averages across all manufacturers and duty cycles. the actual emissions from a particular engine or manufacturer could vary considerably from these levels.

b. "D" and "E" rating for emission factors are due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "D" and "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

c. Total Organic Compounds.

d. Based on emissions data from one engine.

e. Emissions should be estimated based on the assumption that all sulfur in the fuel is converted to SO_2.

f. Based on the assumption that nonmethane organic compounds are 25 percent of TOC emissions from dual fuel engines. Molecular weight of nonmethane gas stream is assumed to be that of methane.

g. Based on assumed 100 percent conversion of carbon in fuel to CO_2 with 87 weight percent carbon in diesel, 70 weight percent carbon in natural gas, dual fuel mixture of 5 percent diesel with 95 percent natural gas, average brake specific fuel consumption of 7000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and natural gas heating value of 23,900 Btu/lb.

TABLE 3.4-3. (ENGLISH AND METRIC UNITS) SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR LARGE STATIONARY DIESEL ENGINES[a]
(Emission Factor Rating: E)[b]

Pollutant	[lb/MMBtu] (fuel input)	[ng/J] (fuel input)
Benzene	7.76 E-04	3.34 E-01
Toluene	2.81 E-04	1.21 E-01
Xylenes	1.93 E-04	8.30 E-02
Propylene	2.79 E-03	1.20 E-00
Formaldehyde	7.89 E-05	3.39 E-02
Acetaldehyde	2.52 E-05	1.08 E-02
Acrolein	7.88 E-06	3.39 E-03

a. Data based on the uncontrolled levels of one diesel engine from reference 5. There was enough information to compute the input specific emission factors of lb/MMBtu, but not enough to calculate the output specific emission factor of g/hp-hr. There was enough information to compute the input specific emission factors of ng/J, but not enough to calculate the output specific emission factor of g/kW-hr.

b. "E" rating for emission factors are due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

TABLE 3.4-4. (ENGLISH AND METRIC UNITS) POLYCYCLIC AROMATIC HYDROCARBON (PAH) EMISSION FACTORS FOR LARGE STATIONARY DIESEL ENGINES[a]
(Emission Factor Rating: E)[b]

Pollutant	[lb/MMBtu] (fuel input)	[ng/J] (fuel input)
Polycyclic Aromatic Hydrocarbons (PAH)		
Naphthalene	1.30 E-04	5.59 E-02
Acenaphthylene	9.23 E-06	3.97 E-03
Acenaphthene	4.68 E-06	2.01 E-03
Fluorene	1.28 E-05	5.50 E-03
Phenanthrene	4.08 E-05	1.75 E-02
Anthracene	1.23 E-06	5.29 E-04
Fluoranthene	4.03 E-06	1.73 E-03
Pyrene	3.71 E-06	1.60 E-03
Benz(a)anthracene	6.22 E-07	2.67 E-04
Chrysene	1.53 E-06	6.58 E-04
Benzo(b)fluoranthene	1.11 E-06	4.77 E-04
Benzo(k)fluoranthene	< 2.18 E-07	< 9.37 E-05
Benzo(a)pyrene	< 2.57 E-07	< 1.10 E-04
Indeno(1,2,3-cd)pyrene	< 4.14 E-07	< 1.78 E-04
Dibenz(a,h)anthracene	< 3.46 E-07	< 1.49 E-04
Benzo(g,h,l)perylene	< 5.56 E-07	< 2.39 E-04
Total PAH	2.12 E-04	9.09 E-02

a.   Data are based on the uncontrolled levels of one diesel engine from reference 5. There was enough information to compute the input specific emission factors of lb/MMBtu and ng/J but not enough to calculate the output specific emission factor of g/hp-hr and g/kW-hr.

b.   "E" rating for emission factors is due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

TABLE 3.4-5. (ENGLISH AND METRIC UNITS) PARTICULATE AND PARTICLE SIZING EMISSION FACTORS FOR LARGE STATIONARY DIESEL ENGINES[a]
(Emission Factor Rating: E)[b]

Pollutant	Power Output		Fuel Input	
	[grams/hp-hr]	[grams/kW-hr]	[lb/MMBtu]	[ng/J]
Particulate Size Distribution				
<1 µm	0.1520	0.2038	0.0478	20.56
1-3 µm	0.0004	0.0005	0.0001	0.05
3-10 µm	0.0054	0.0072	0.0017	0.73
>10 µm	0.0394	0.0528	0.0124	5.33
Total PM-10 (≤10 µm)	0.1578	0.2116	0.0496	21.34
TOTAL	0.1972	0.2644	0.0620	26.67
Particulate Emissions				
Solids	0.2181	0.2925	0.0686	29.49
Condensables	0.0245	0.0329	0.0077	3.31
TOTAL	0.2426	0.3253	0.0763	32.81

a. Data are based on the uncontrolled levels of one diesel engine from reference 6. The data for the particulate emissions were collected using Method 5 and the particle size distributions were collected using a Source Assessment Sampling System (SASS).

b. "E" rating for emission factors is due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

TABLE 3.4-6. NO$_x$ REDUCTION AND FUEL CONSUMPTION PENALTIES FOR
LARGE STATIONARY DIESEL AND DUAL FUEL ENGINES[a]

Control Approach		Diesel		Dual Fuel	
		Percent NO$_x$ Reduction	ΔBSFC,[b] Percent	Percent NO$_x$ Reduction	ΔBSFC,[b] Percent
Derate	10%			<20	4
	20%	<20	4		
	25%	5-23	1-5	1-33	1-7
Retard	2°	<20	4	<20	3
	4°	<40	4	<40	1
	8°	28-45	2-8	50-73	3-5
Air-to-Fuel	3%			<20	0
	±10%	7-8	3	25-40	1-3
Water Injection (H$_2$O/fuel ratio)	50%	25-35	2-4		
Selective Catalytic Reduction (SCR)		80-95	0	80-95	0

a. Data are based on references 1, 2, and 3. The reductions shown are typical and will vary depending on the engine and duty cycle.

b. BSFC = Brake Specific Fuel Consumption.

References for Section 3.4

1. Lips, H. I., J. A. Gotterba, and K. J. Lim, <u>Environmental Assessment of Combustion Modification Controls for Stationary Internal Combustion Engines</u>, EPA-600/7-81-127, Industrial Environmental Research Laboratory, Office of Environmental Engineering and Technology, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1981,

2. Campbell, L. M., D. K. Stone, and G. S. Shareef, <u>Sourcebook: NO$_x$ Control Technology Data, Control Technology Center</u>, EPA-600/2-91-029, Emission Standards Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1991.

3. Catalysts for Air Pollution Control, brochure by the Manufacturers of Emission Controls Association (MECA), Washington, DC, March 1992.

4. <u>Standards Support and Environmental Impact Statement, Volume I: Stationary Internal Combustion Engines</u>, EPA-450/2-78-125a, Emission Standards and Engineering Division, Office of Air, Noise, and Radiation, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1979.

5. <u>Pooled Source Emission Test Report: Oil and Gas Production Combustion Sources, Fresno and Ventura Counties, California</u>, Report prepared by ENSR Consulting and Engineering for Western States Petroleum Association (WSPA), Bakersfield, CA, December 1990, ENSR # 7230-007-700.

6. Castaldini, C., <u>Environmental Assessment of NO$_x$ Control on a Compression Ignition Large Bore Reciprocating Internal Combustion Engine, Volume I: Technical Results</u>, EPA-600/7-86/001a, Combustion Research Branch of the Energy Assessment and Control Division, Industrial Environmental Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, Washington, D.C., April 1984.

Emissions And Controls[2-3] - In the bathing and mixing of fine dry ingredients to form slurry, dust emissions are generated at scale hoppers, mixers and crushers. Fabric filters are used, not only to reduce or to eliminate the dust emissions but also to recover raw materials. Emission factors for particulate from spray drying operations are shown in Table 5.15-1. Table 5.15-2 gives size specific particulate emission factors for operations on which information is available. There is also a minor source of volatile organics when the product being sprayed contains organic material with low vapor pressures. In the tower exhaust air stream, these vaporized organic materials condense into droplets or particles.

Dry cyclones and cyclonic impingement scrubbers are the primary collection equipment employed to capture the detergent dust in the spray dryer exhaust for return to process. Dry cyclones are used, in parallel or in series, to collect particulate (detergent dust) and to recycle it back to the crusher. Cyclonic impinged scrubbers are used, in parallel, to collect the particulate from a scrubbing slurry and to recycle it to the crushher. Secondary collection equipment is used to collect the fine particulate that has escaped from the primary devices. Cyclonic impingement scrubbers are often followed by mist eliminators, and dry cyclones are followed by fabric filters or scrubber/electrostatic precipitator units. Conveying, mixing and packaging of detergent granules can cause dust emissions. Usually, fabric filters provide the best control.

TABLE 5.15-1. EMISSION FACTORS FOR DETERGENT SPRAY DRYING[a]

EMISSION FACTOR RATING: B

Control device	Efficiency (%)	Particulate	
		Kg/Mg of product	lb/ton of product
Uncontrolled	NA	45	90
Cyclone[b]	85	7	14
Cyclone			
w/Spray chamber	92	3.5	7
w/Packed scrubber	95	2.5	5
w/Venturi scrubber	97	1.5	3
w/Wet scrubber	99	0.544	1.08
w/Wet scrubber/ESP	99.9	0.023	0.046
Fabric filter	99	0.54	1.1

[a]References 4-8. VOC emissions data have not been reported in the literature. NA = not applicable. ESP = electrostatic precipitator.
[b]Some type of primary collector, such as a cyclone, is considered integral to a spray drying system.

TABLE 5.15-2. PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR DETERGENT SPRAY DRYING[a]

EMISSION FACTOR RATING: D

Control device	Particle size distribution[b] (Cum. wt. %)			Particulate emission factor[c] (kg/Mg)		
	$\leq$2.5 um	$\leq$6.0 um	$\leq$10.0 um	$\leq$2.5 um	$\leq$6.0 um	$\leq$10.0 um
Uncontrolled	50.2	60.4	66.1	23	27	30
Fabric filter	61.9	76.5	81.8	0.33	0.41	0.44
Cyclone	74.5	90.8	95.8	5.2	6.4	6.7
Cyclone and wet scrubber	86.5	100	100	0.470	0.544	0.544
Cyclone and wet scrubber/ electrostatic precipitator	97.0	97.7	99.9	0.023	0.023	0.023

[a]References 9-14.
[b]Cumulative weight % of particles $\leq$ corresponding particle diameter.
[c]Cumulative weight % of particles $\leq$ corresponding particle size. Equals total particulate emission factor (Table 5.15-1) x particle size distribution (%)/100. Expressed as units/unit weight of product.

STORAGE OF ORGANIC LIQUIDS

12.1 PROCESS DESCRIPTION[1,2]

Storage vessels containing organic liquids can be found in many industries, including (1) petroleum producing and refining, (2) petrochemical and chemical manufacturing, (3) bulk storage and transfer operations, and (4) other industries consuming or producing organic liquids. Organic liquids in the petroleum industry, usually called petroleum liquids, generally are mixtures of hydrocarbons having dissimilar true vapor pressures (for example, gasoline and crude oil). Organic liquids in the chemical industry, usually called volatile organic liquids, are composed of pure chemicals or mixtures of chemicals with similar true vapor pressures (for example, benzene or a mixture of isopropyl and butyl alcohols).

Five basic tank designs are used for organic liquid storage vessels: fixed roof (vertical and horizontal), external floating roof, internal floating roof, variable vapor space, and pressure (low and high). A brief description of each tank is provided below. Loss mechanisms associated with each type of tank are provided in Section 12.2.

Fixed Roof Tanks - A typical vertical fixed roof tank is shown in Figure 12.1-1. This type of tank consists of a cylindrical steel shell with a permanently affixed roof, which may vary in design from cone- or dome-shaped to flat.

Fixed roof tanks are either freely vented or equipped with a pressure/vacuum vent. The latter allows them to operate at a slight internal pressure or vacuum to prevent the release of vapors during very small changes in temperature, pressure, or liquid level. Of current tank designs, the fixed roof tank is the least expensive to construct and is generally considered the minimum acceptable equipment for storing organic liquids.

Horizontal fixed roof tanks are constructed for both above-ground and underground service and are usually constructed of steel, steel with a fiberglass overlay, or fiberglass-reinforced polyester. Horizontal tanks are generally small storage tanks with capacities of less than 40,000 gallons. Horizontal tanks are constructed such that the length of the tank is not greater than six times the diameter to ensure structural integrity. Horizontal tanks are usually equipped with pressure-vacuum vents, gauge hatches and sample wells, and manholes to provide access to these tanks. In addition, underground tanks are cathodically protected to prevent corrosion of the tank shell. Cathodic protection is accomplished by placing sacrificial anodes in the tank that are connected to an impressed current system or by using galvanic anodes in the tank.

The potential emission sources for above-ground horizontal tanks are the same as those for vertical fixed roof tanks. Emissions from underground storage tanks are associated mainly with changes in the liquid level in the tank. Losses due to changes in temperature or barometric pressure are minimal for underground tanks because the surrounding earth limits the diurnal temperature change, and changes in the barometric pressure result in only small losses.

External Floating Roof Tanks - A typical external floating roof tank consists of an open-topped cylindrical steel shell equipped with a roof that floats on the surface of the stored liquid. Floating roof tanks that are currently in use are constructed of welded steel plate and are of two general types: pontoon or double-deck. Pontoon-type and double-deck-type external floating roofs are shown in Figures 12.1-2 and 12.1-3, respectively. With all types of external floating roof tanks, the roof rises and falls with the liquid level in the tank. External floating roof tanks are equipped with a seal system, which is attached to the roof perimeter and contacts the tank wall. The purpose of the floating roof and seal system is to reduce evaporative loss of the stored liquid. Some annular space remains between the seal system and the tank wall. The seal system slides against the tank wall as the roof is raised and lowered. The floating roof is also equipped with roof fittings that penetrate the floating roof and serve operational functions. The external floating roof design is such that evaporative losses from the stored liquid are limited to losses from the seal system and roof fittings (standing storage loss) and any exposed liquid on the tank walls (withdrawal loss).

Internal Floating Roof Tanks - An internal floating roof tank has both a permanent fixed roof and a floating deck inside. The terms "deck" and "floating roof" can be used interchangeably in reference to the structure floating on the liquid inside the tank. There are two basic types of internal floating roof tanks: tanks in which the fixed roof is supported by vertical columns within the tank, and tanks with a self-supporting fixed roof and no internal support columns. Fixed roof tanks that have been retrofitted to use a floating deck are typically of the first type. External floating roof tanks that have been converted to internal floating roof tanks typically have a self-supporting roof. Newly constructed internal floating roof tanks may be of either type. The deck in internal floating roof tanks rises and falls with the liquid level and either floats directly on the liquid surface (contact deck) or rests on pontoons several inches above the liquid surface (noncontact deck). The majority of aluminum internal floating roofs currently in service are noncontact decks. Typical contact deck and noncontact deck internal floating roof tanks are shown in Figure 12.1-4.

Contact decks can be (1) aluminum sandwich panels that are bolted together, with a honeycomb aluminum core floating in contact with the liquid; (2) pan steel decks floating in contact with the liquid, with or without pontoons; and (3) resin-coated, fiberglass reinforced polyester (FRP), buoyant panels floating in contact with the liquid. The majority of internal contact floating roofs currently in service are aluminum sandwich panel-type or pan steel-type. The FRP roofs are less common. The panels of pan steel decks are usually welded together.

Typical noncontact decks have an aluminum deck and an aluminum grid framework supported above the liquid surface by tubular aluminum pontoons or some other buoyant structure. The noncontact decks usually have bolted deck seams. Installing a floating roof or deck minimizes evaporative losses of the stored liquid. As with the external floating roof tanks, both contact and noncontact decks incorporate rim seals and deck fittings for the same purposes previously described for external floating roof tanks. Evaporation losses from decks may come from deck fittings, nonwelded deck seams, and the annular space between the deck and tank wall. In addition, these tanks are freely vented by circulation vents at the top of the fixed roof. The vents minimize the possibility of organic vapor accumulation in

concentrations approaching the flammable range. An internal floating roof tank not freely vented is considered a pressure tank. Emission estimation methods for such tanks are not provided in AP-42.

Variable Vapor Space Tanks - Variable vapor space tanks are equipped with expandable vapor reservoirs to accommodate vapor volume fluctuations attributable to temperature and barometric pressure changes. Although variable vapor space tanks are sometimes used independently, they are normally connected to the vapor spaces of one or more fixed roof tanks. The two most common types of variable vapor space tanks are lifter roof tanks and flexible diaphragm tanks.

Lifter roof tanks have a telescoping roof that fits loosely around the outside of the main tank wall. The space between the roof and the wall is closed by either a wet seal, which is a trough filled with liquid, or a dry seal, which uses a flexible coated fabric.

Flexible diaphragm tanks use flexible membranes to provide expandable volume. They may be either separate gasholder units or integral units mounted atop fixed roof tanks.

Variable vapor space tank losses occur during tank filling when vapor is displaced by liquid. Loss of vapor occurs only when the tank's vapor storage capacity is exceeded.

Pressure Tanks - Two classes of pressure tanks are in general use: low pressure (2.5 to 15 psig) and high pressure (higher than 15 psig). Pressure tanks generally are used for storing organic liquids and gases with high vapor pressures and are found in many sizes and shapes, depending on the operating pressure of the tank. Pressure tanks are equipped with a pressure/vacuum vent that is set to prevent venting loss from boiling and breathing loss from daily temperature or barometric pressure changes. High-pressure storage tanks can be

operated so that virtually no evaporative or working losses occur. In low-pressure tanks, working losses can occur with atmospheric venting of the tank during filling operations. No appropriate correlations are available to estimate vapor losses from pressure tanks.
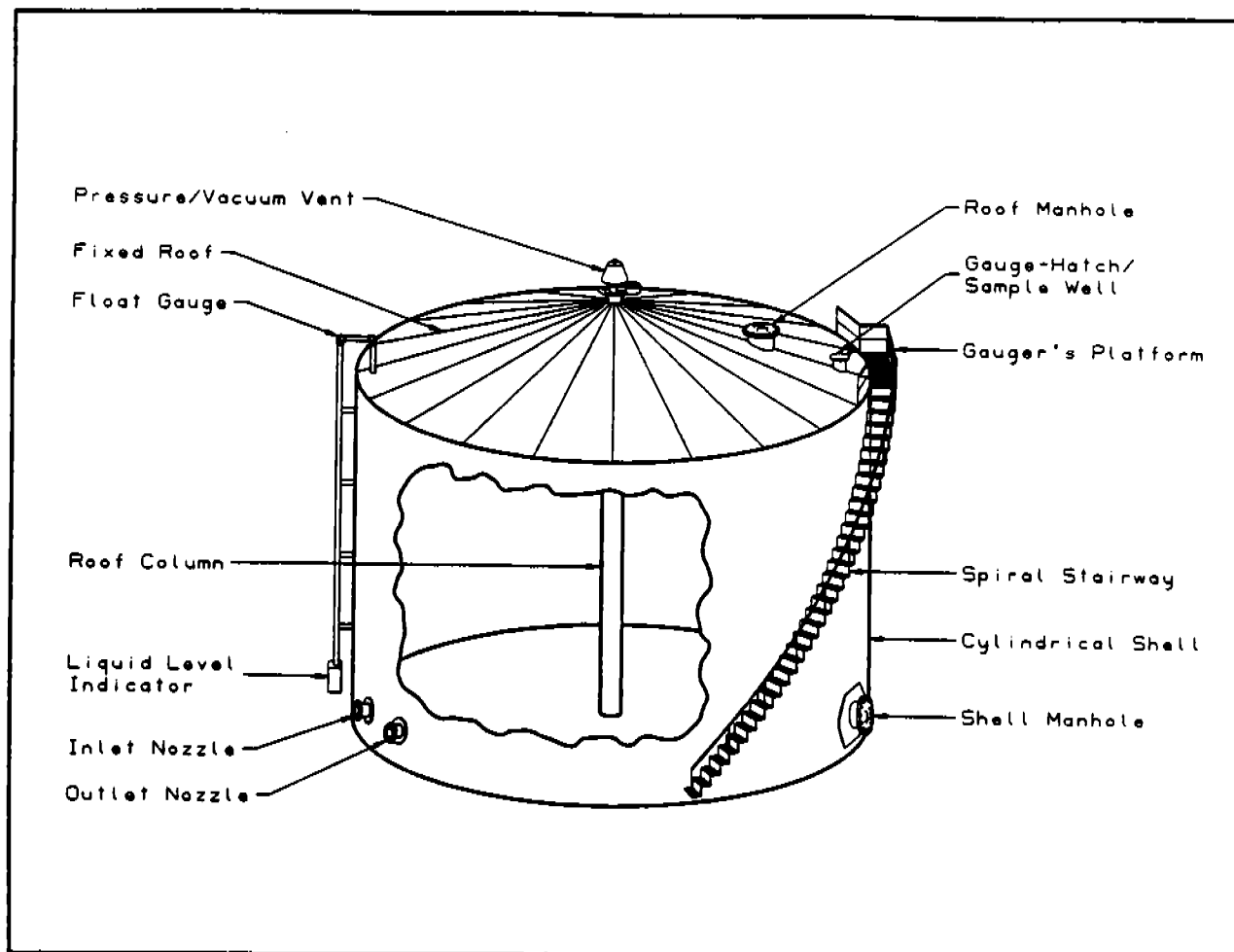
Figure 12.1-1. Typical fixed-roof tank.[1]
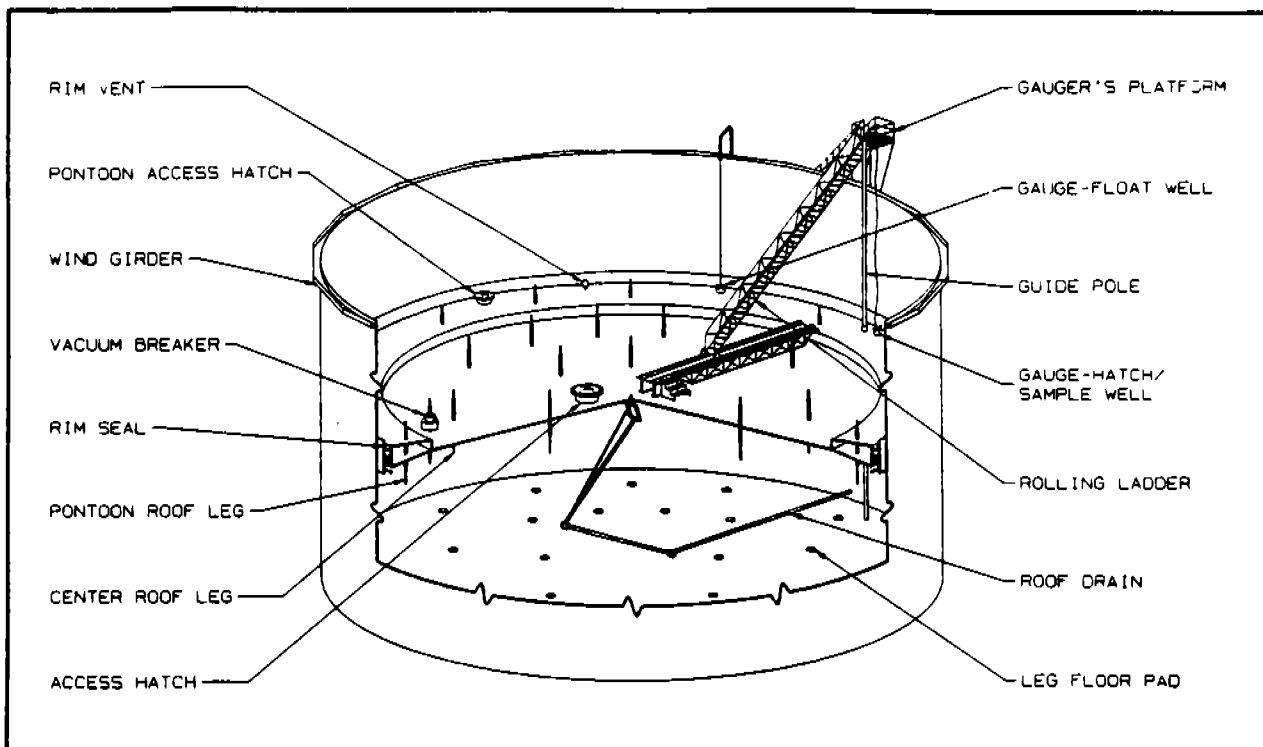
Figure 12.1-2. External floating roof tank (pontoon type).[1]
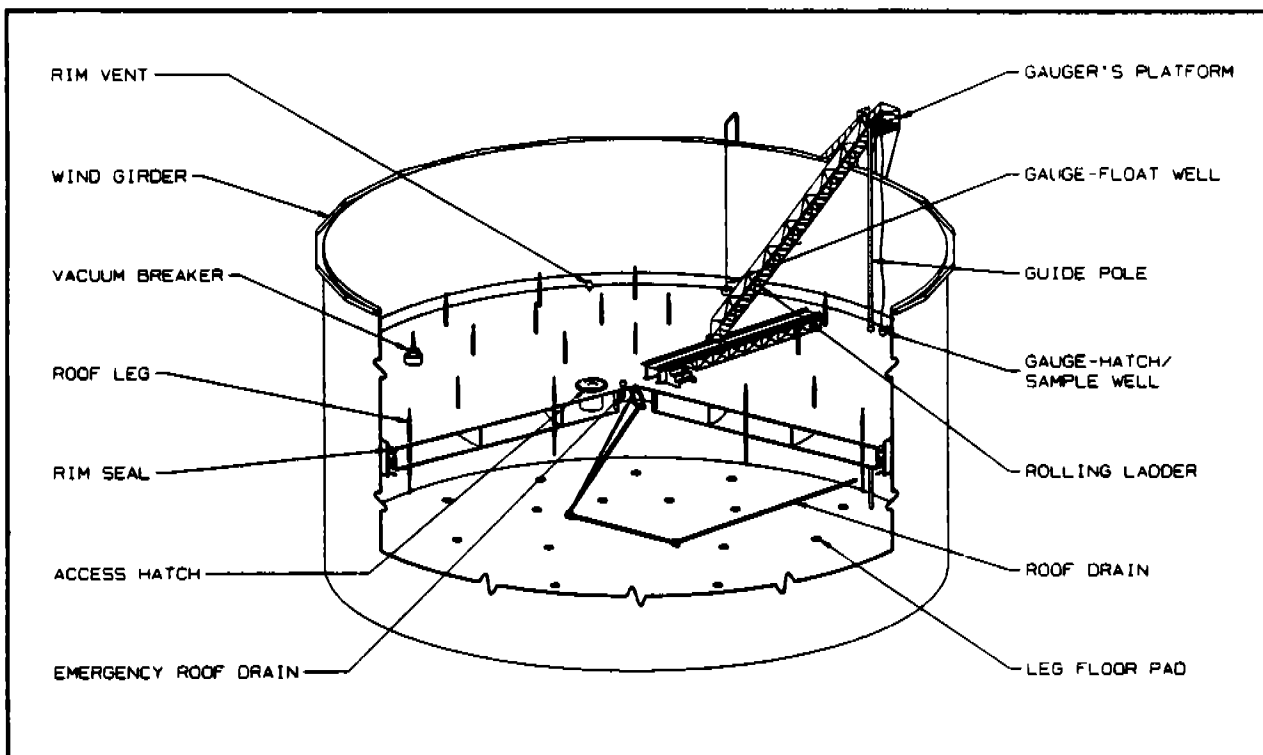
Figure 12.1-3. External floating roof tank (double-deck type).[1]
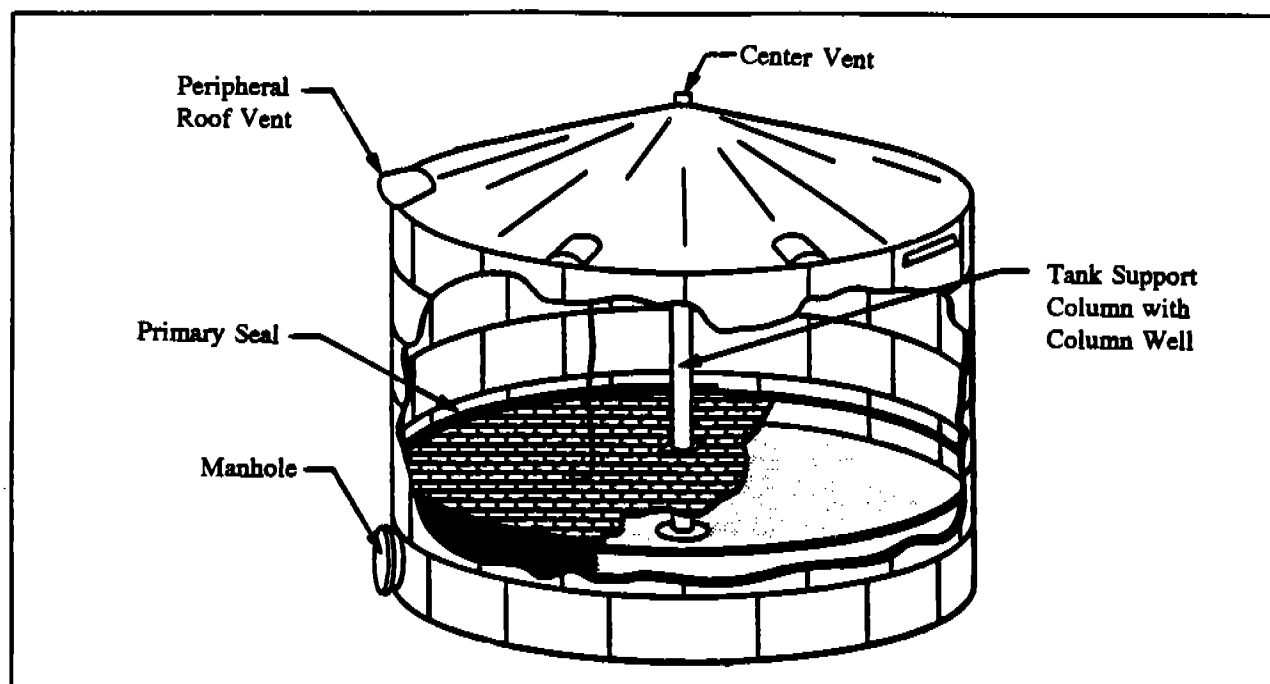
a. Contact internal floating roof
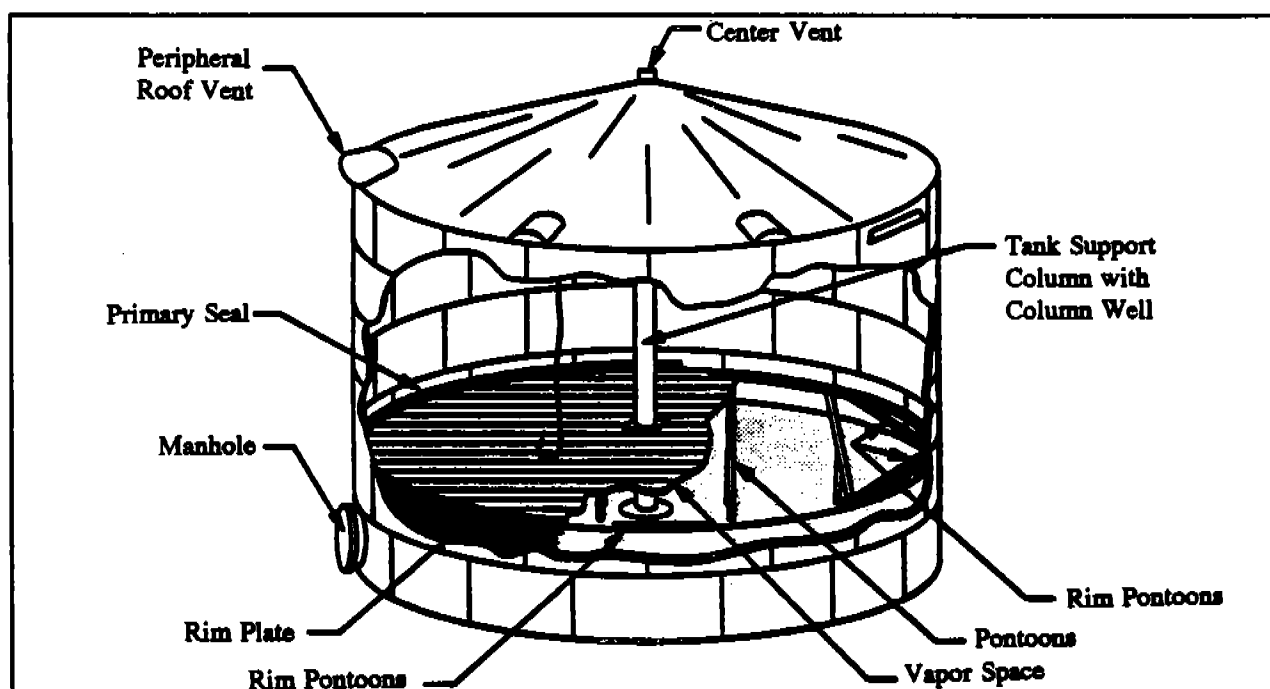
b. Noncontact internal floating roof.

Figure 12.1-4. Internal floating roof tanks.[2]

12.2 EMISSION MECHANISMS AND CONTROL

Emissions from organic liquids in storage occur because of evaporative loss of the liquid during its storage and as a result of changes in the liquid level. The emission sources vary with tank design, as does the relative contribution of each type of emission source. Emissions from fixed roof tanks are a result of evaporative losses during storage and are known as breathing losses (or standing storage losses), and evaporative losses during filling and emptying operations are known as working losses. External and internal floating roof tanks are emission sources because of evaporative losses that occur during standing storage and withdrawal of liquid from the tank. Standing storage losses are a result of evaporative losses through rim seals, deck fittings, and/or deck seams. The loss mechanisms for fixed roof and external and internal floating roof tanks are described in more detail in the following sections. Variable vapor space tanks are also emission sources because of evaporative losses that result during filling operations. The loss mechanism for variable vapor space tanks is also described in this section. Emissions occur from pressure tanks, as well. However, loss mechanisms from these sources are not described in this chapter.

12.2.1 Fixed Roof Tanks

The two significant types of emissions from fixed roof tanks are storage and working losses. Storage loss is the expulsion of vapor from a tank through vapor expansion and contraction, which are the results of changes in temperature and barometric pressure. This loss occurs without any liquid level change in the tank.

The combined loss from filling and emptying is called working loss. Evaporation during filling operations is a result of an increase in the liquid level in the tank. As the liquid level increases, the pressure inside the tank exceeds the relief pressure and vapors are expelled from the tank. Evaporative loss during emptying occurs when air drawn into the tank during liquid removal becomes saturated with organic vapor and expands, thus exceeding the capacity of the vapor space.

Fixed roof tank emissions vary as a function of vessel capacity, vapor pressure of the stored liquid, utilization rate of the tank, and atmospheric conditions at the tank location.

Several methods are used to control emissions from fixed roof tanks. Emissions from fixed roof tanks can be controlled by installing an internal floating roof and seals to minimize evaporation of the product being stored. The control efficiency of this method ranges from 60 to 99 percent, depending on the type of roof and seals installed and on the type of organic liquid stored.

Vapor balancing is another means of emission control. Vapor balancing is probably most common in the filling of tanks at gasoline stations. As the storage tank is filled, the vapors expelled from the storage tank are directed to the emptying gasoline tanker truck. The truck then transports the vapors to a centralized station where a vapor recovery or control system is used to control emissions. Vapor balancing can have control efficiencies as high as 90 to 98 percent if the vapors are subjected to vapor recovery or control. If the

truck vents the vapor to the atmosphere instead of to a recovery or control system, no control is achieved.

Vapor recovery systems collect emissions from storage vessels and convert them to liquid product. Several vapor recovery procedures may be used, including vapor/liquid absorption, vapor compression, vapor cooling, vapor/solid adsorption, or a combination of these. The overall control efficiencies of vapor recovery systems are as high as 90 to 98 percent, depending on the methods used, the design of the unit, the composition of vapors recovered, and the mechanical condition of the system.

In a typical thermal oxidation system, the air/vapor mixture is injected through a burner manifold into the combustion area of an incinerator. Control efficiencies for this system can range from 96 to 99 percent.

12.2.2 External Floating Roof Tanks[2,3,5]

Total emissions from external floating roof tanks are the sum of withdrawal losses and standing storage losses. Withdrawal losses occur as the liquid level, and thus the floating roof, is lowered. Some liquid remains attached to the tank surface and is exposed to the atmosphere. Evaporative losses will occur until the tank is filled and the exposed surface (with the liquid) is again covered. Standing storage losses from external floating roof tanks include rim seal and roof fitting losses. Rim seal losses can occur through many complex mechanisms, but the majority of rim seal vapor losses have been found to be wind-induced. Other potential standing storage loss mechanisms include breathing losses as a result of temperature and pressure changes. Also, standing storage losses can occur through permeation of the seal material with vapor or via a wicking effect of the liquid. Testing has indicated that breathing, solubility, and wicking loss mechanisms are small in comparison to the wind-induced loss. Also, permeation of the seal material generally does not occur if the correct seal fabric is used. The rim seal loss factors incorporate all types of losses.

The roof fitting losses can be explained by the same mechanisms as the rim seal loss mechanisms. However, the relative contribution of each is not known. The roof fitting losses identified in this section account for the combined effect of all of the mechanisms.

A rim seal system is used to allow the floating roof to travel within the tank as the liquid level changes. The seal system also helps to fill the annular space between the rim and the tank shell and therefore minimize evaporative losses from this area. A rim seal system may consist of just a primary seal or a primary seal and a secondary seal, which is mounted above the primary seal. Examples of primary and secondary seal configurations are shown in Figures 12.2-1 through 12.2-3. Three basic types of primary seals are used on external floating roofs: mechanical (metallic) shoe, resilient filled (nonmetallic), and flexible wiper. The resilient seal can be mounted to eliminate the vapor space between the seal and liquid surface (liquid mounted) or to allow a vapor space between the seal and liquid surface (vapor mounted). A primary seal serves as a vapor conservation device by closing the annular space between the edge of the floating roof and the tank wall. Some primary seals are protected by a metallic weather shield. Additional evaporative loss may be controlled by

a secondary seal. Secondary seals can be either flexible wiper seals or resilient filled seals. Two configurations of secondary seals are currently available: shoe mounted and rim mounted. Although there are other seal systems, the systems described here include the majority in use today.

Roof fitting loss emissions from external floating roof tanks result from penetrations in the roof by deck fittings, the most common of which are described below. Roof fittings are also shown in Figures 12.2-4 and 12.2-5. Some of the fittings are typical of both external and internal floating roof tanks.

1. Access hatch. An access hatch is an opening in the deck with a peripheral vertical well that is large enough to provide passage for workers and materials through the deck for construction or servicing. Attached to the opening is a removable cover that may be bolted and/or gasketed to reduce evaporative loss. On internal floating roof tanks with noncontact decks, the well should extend down into the liquid to seal off the vapor space below the noncontact deck. A typical access hatch is shown in Figure 12.2-4a.

2. Gauge-float well. A gauge-float is used to indicate the level of liquid within the tank. The float rests on the liquid surface and is housed inside a well that is closed by a cover. The cover may be bolted and/or gasketed to reduce evaporation loss. As with other similar deck penetrations, the well extends down into the liquid on noncontact decks in internal floating roof tanks. A typical gauge-float well is shown in Figure 12.2-4b.

3. Gauge-hatch/sample well. A gauge-hatch/sample well consists of a pipe sleeve equipped with a self-closing gasketed cover (to reduce evaporative losses) and allows hand-gauging or sampling of the stored liquid. The gauge-hatch/sample well is usually located beneath the gauger's platform, which is mounted on top of the tank shell. A cord may be attached to the self-closing gasketed cover so that the cover can be opened from the platform. A typical gauge-hatch/sample well is shown in Figure 12.2-4c.

4. Rim vents. Rim vents are usually used only on tanks equipped with a mechanical-shoe primary seal. A typical rim vent is shown in Figure 12.2-4d. The vent is used to release any excess pressure or vacuum that is present in the vapor space bounded by the primary-seal shoe and the floating roof rim and the primary seal fabric and the liquid level. Rim vents usually consist of weighted pallets that rest on a gasketed cover.

5. Roof drains. Currently two types of roof drains are in use (closed and open roof drains) to remove rainwater from the floating roof surface. Closed roof drains carry rainwater from the surface of the roof though a flexible hose or some other type of piping system that runs through the stored liquid prior to exiting the tank. The rainwater does not come in contact with the liquid, so no evaporative losses result.

Open roof drains can be either flush or overflow drains and are used only on double-deck external floating roofs. Both types consist of a pipe that extends below the roof to allow the rainwater to drain into the stored liquid. The liquid from the tank enters the pipe, so evaporative losses can result from the tank opening. Flush drains are flush with the

Storage of Organic Liquids

roof surface. Overflow drains are elevated above the roof surface. A typical overflow roof drain is shown in Figure 12.2-5a. Overflow drains are used to limit the maximum amount of rainwater that can accumulate on the floating roof, providing emergency drainage of rainwater if necessary. Overflow drains are usually used in conjunction with a closed drain system to carry rainwater outside the tank.

6. Roof leg. To prevent damage to fittings underneath the deck and to allow for tank cleaning or repair, supports are provided to hold the deck at a predetermined distance off the tank bottom. These supports consist of adjustable or fixed legs attached to the floating deck or hangers suspended from the fixed roof. For adjustable legs or hangers, the load-carrying element passes through a well or sleeve into the deck. With noncontact decks, the well should extend into the liquid. Evaporative losses may occur in the annulus between the roof leg and its sleeve. A typical roof leg is shown in Figure 12.2.5b.

7. Unslotted guidepole wells. A guidepole well is an antirotational device that is fixed to the top and bottom of the tank, passing through the floating roof. The guidepole is used to prevent adverse movement of the roof and thus damage to roof fittings and the rim seal system. A typical guidepole well is shown in Figure 12.2-5c.

8. Slotted guidepole/sample wells. The function of the slotted guidepole/sample well is similar to the unslotted guidepole well but also has additional features. A typical slotted guidepole well is shown in Figure 12.2-5d. As shown in this figure, the guide pole is slotted to allow stored liquid to enter. The liquid entering the guidepole is well mixed, having the same composition as the remainder of the stored liquid, and is at the same liquid level as the liquid in the tank. Representative samples can therefore be collected from the slotted guidepole. The opening at the top of the guidepole and along the exposed sides is typically the emission source. However, evaporative loss from the top of the guidepole can be reduced by placing a float inside the guidepole.

9. Vacuum breaker. A vacuum breaker equalizes the pressure of the vapor space across the deck as the deck is either being landed on or floated off its legs. A typical vacuum breaker is shown in Figure 12.2-5e. As depicted in this figure, the vacuum breaker consists of a well with a cover. Attached to the underside of the cover is a guided leg long enough to contact the tank bottom as the floating deck approaches. When in contact with the tank bottom, the guided leg mechanically opens the breaker by lifting the cover off the well; otherwise, the cover closes the well. The closure may be gasketed or ungasketed. Because the purpose of the vacuum breaker is to allow the free exchange of air and/or vapor, the well does not extend appreciably below the deck.
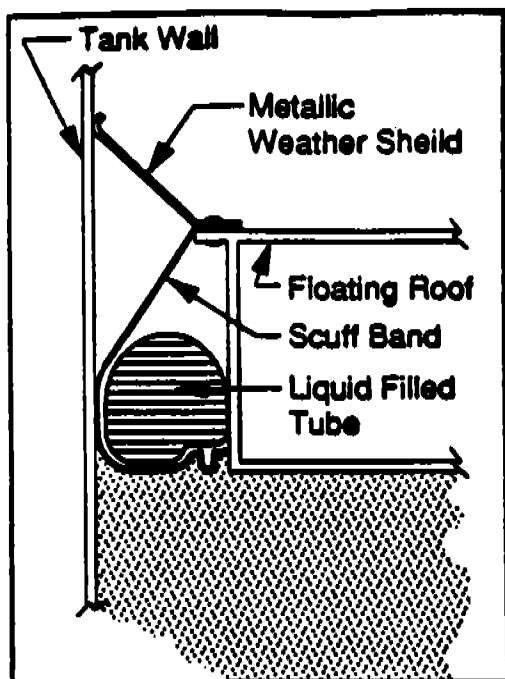
a. Liquid-filled seal with weather shield.
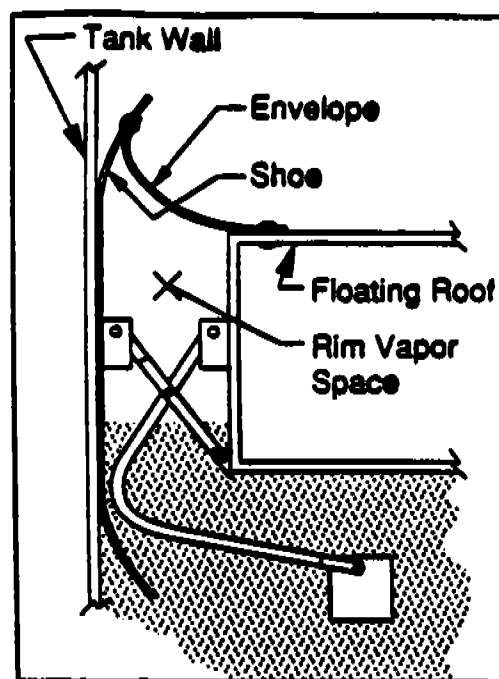
b. Metallic shoe seal.
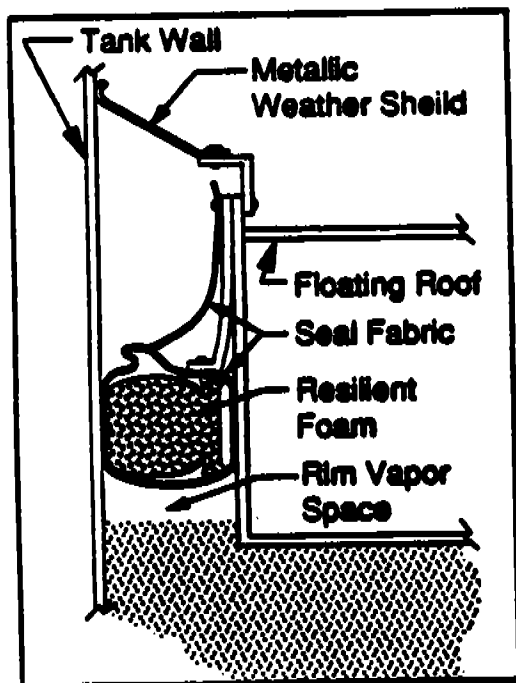
c. Vapor-mounted resilient foam-filled seal with weather shield.
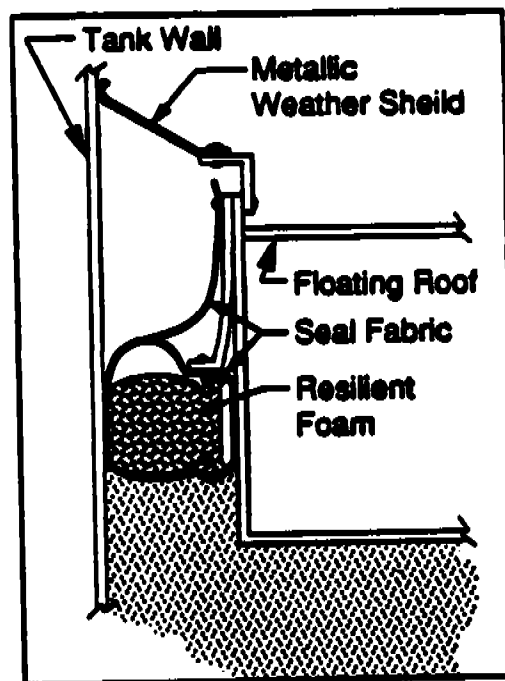
d. Liquid-mounted resilient foam-filled seal with weather shield.

Figure 12.2-1. Primary seals.[2]
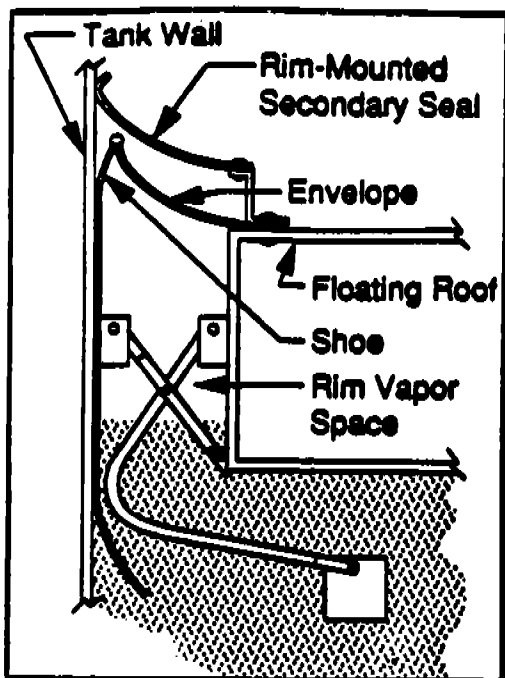
a. Shoe seal with rim-mounted
   secondary seal.
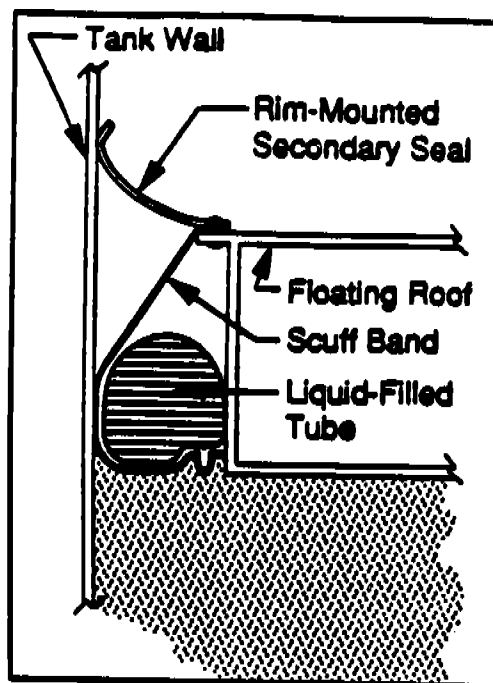
b. Liquid-filled seal with rim-
   mounted secondary seal.
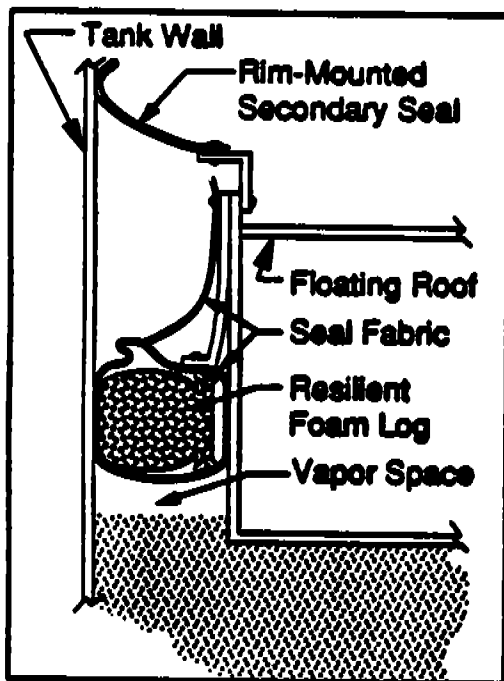
c. Resilient foam seal (vapor-
   mounted) with rim-mounted
   secondary seal.
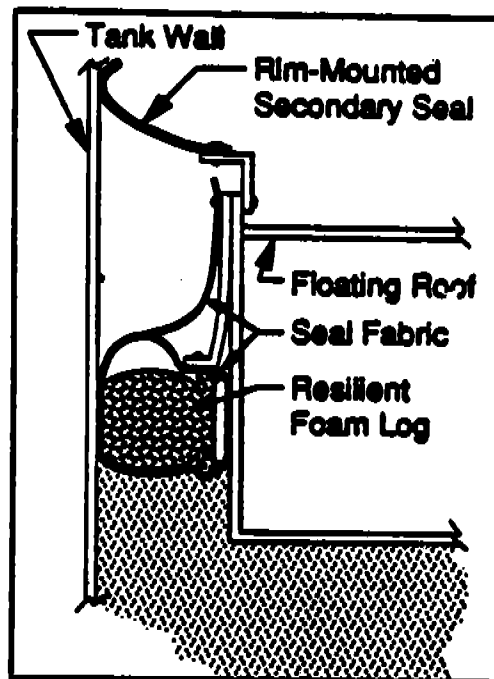
d. Resilient foam seal (liquid
   mounted) with rim-mounted
   secondary seal.

Figure 12.2-2. Rim-mounted secondary seals
on external floating roofs.
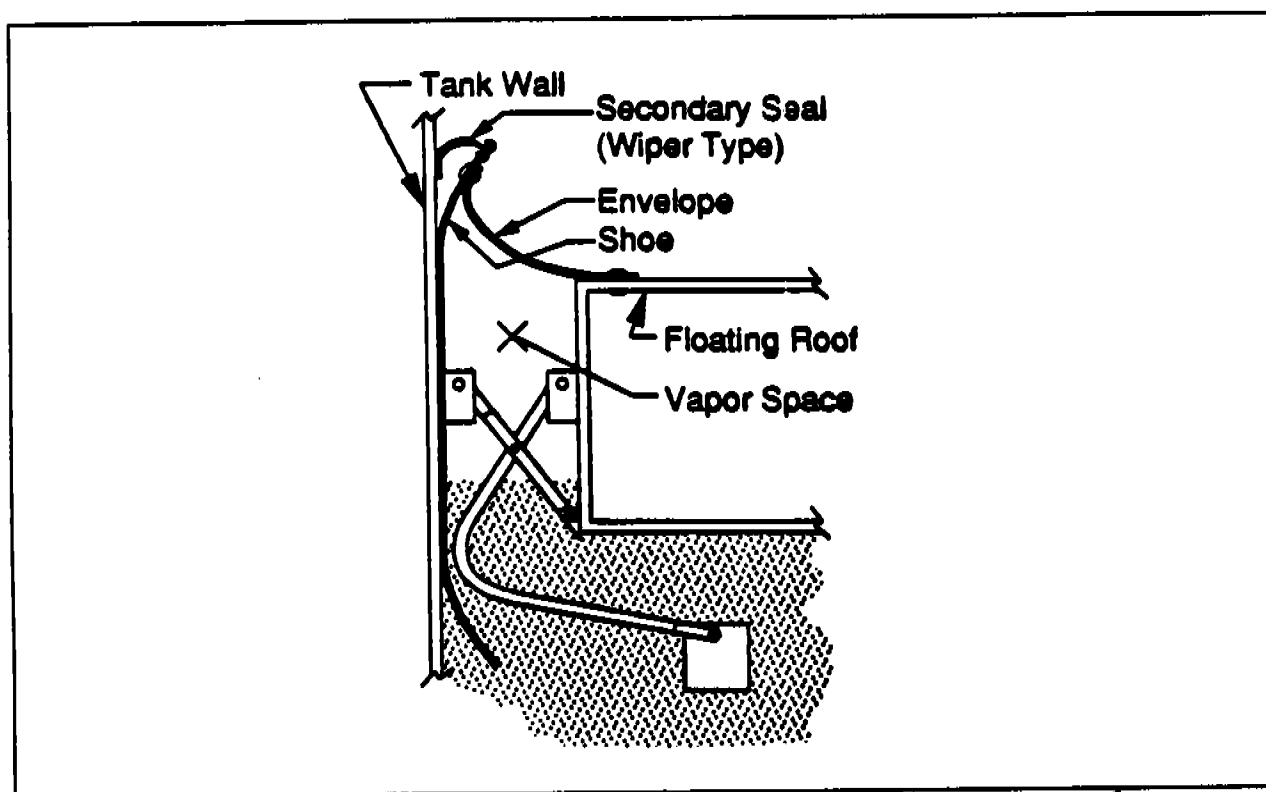
Figure 12.2-3. Metallic shoe seal with shoe-mounted secondary seal.[5]
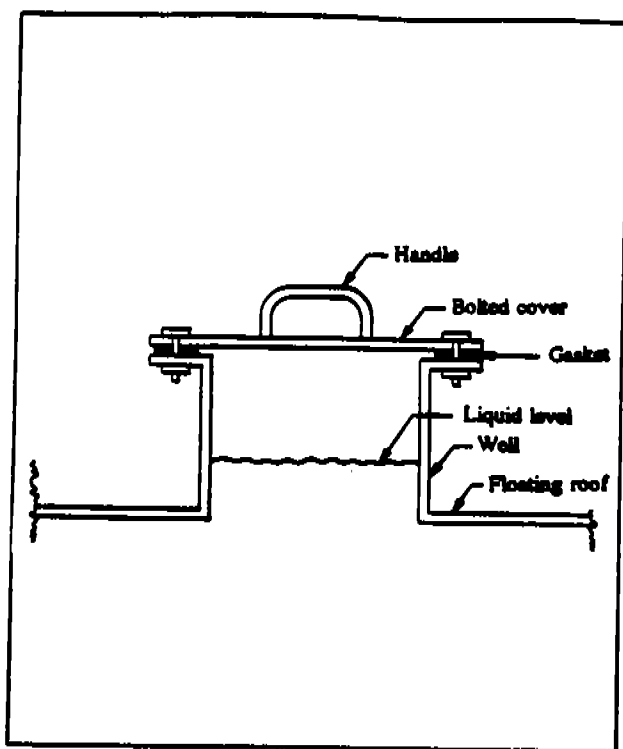
a. Access hatch
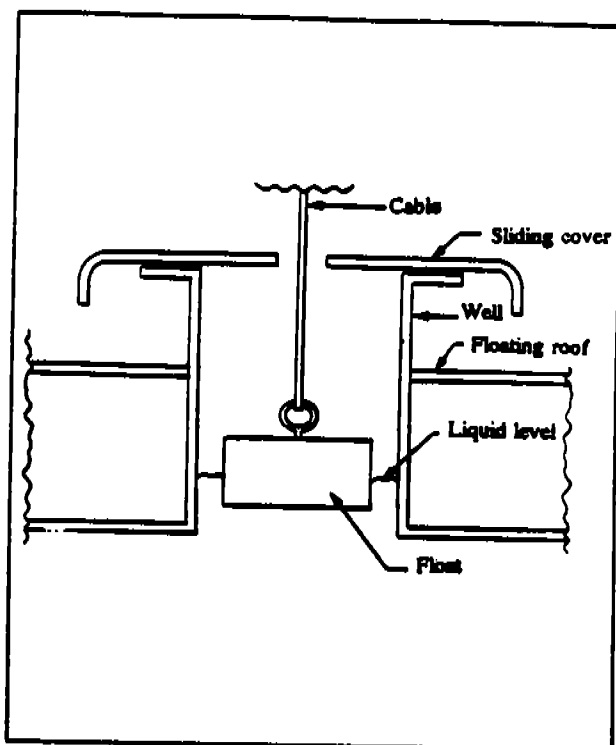
b. Gauge-float well
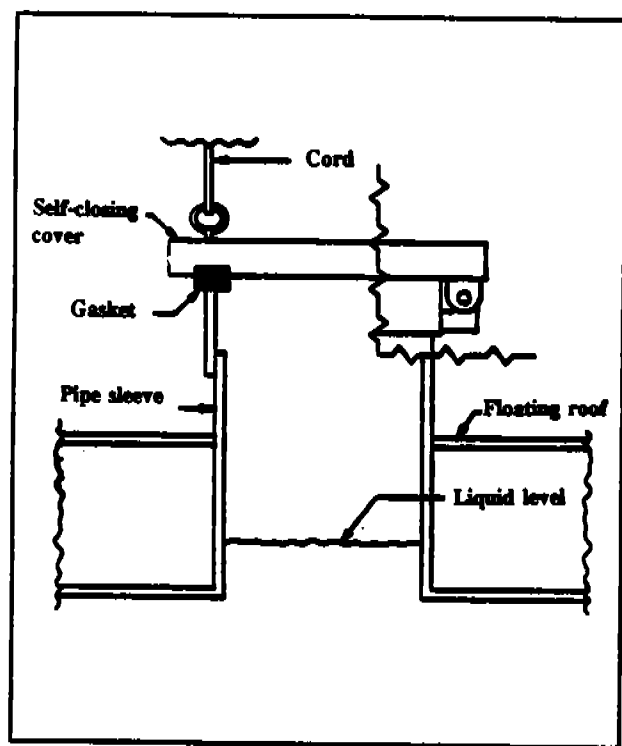
c. Gauge-hatch/sample well
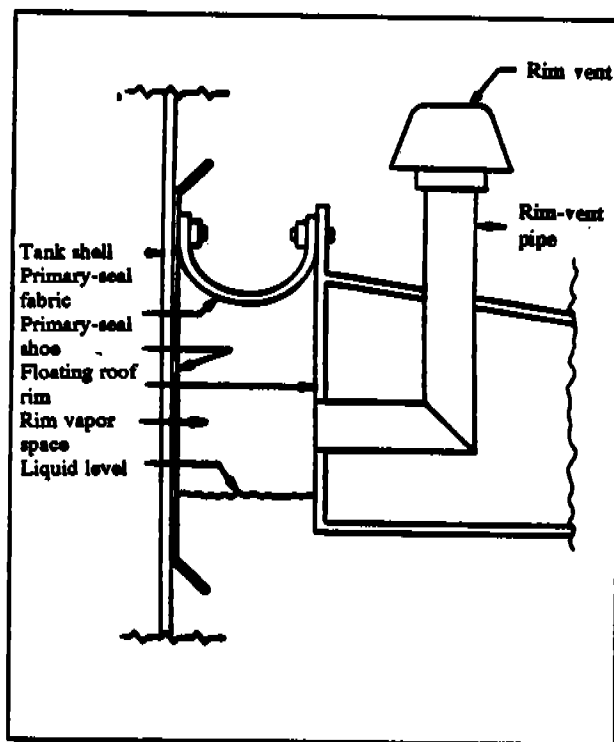
d. Rim vent

Figure 12.2-4. Roof fittings for external floating roof tanks.[3]
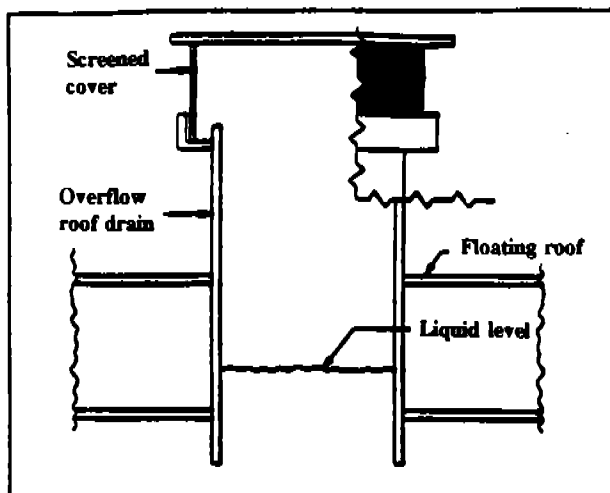
a. Overflow drain
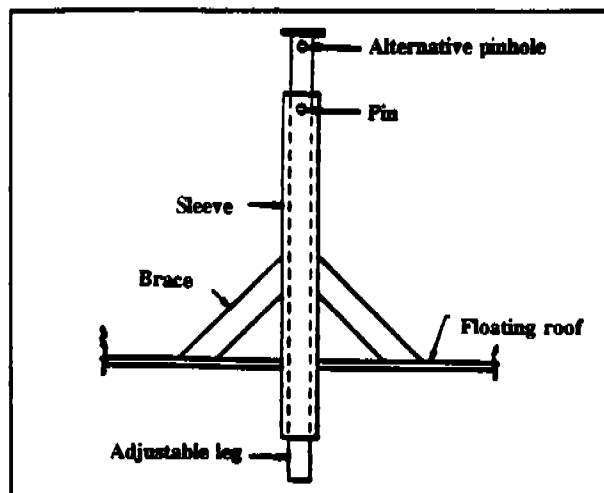
b. Roof leg
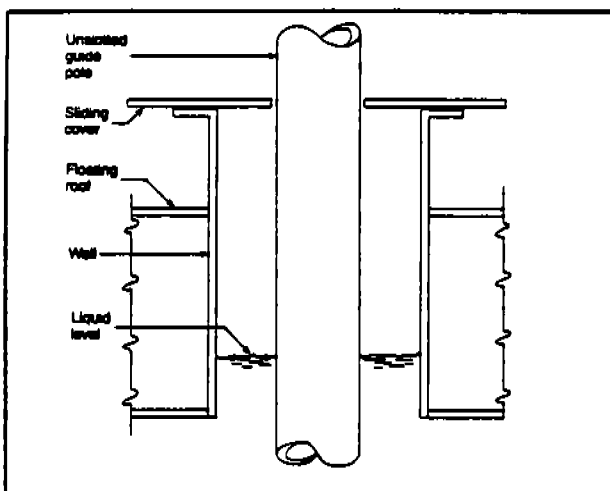
c. Unslotted guide pole well
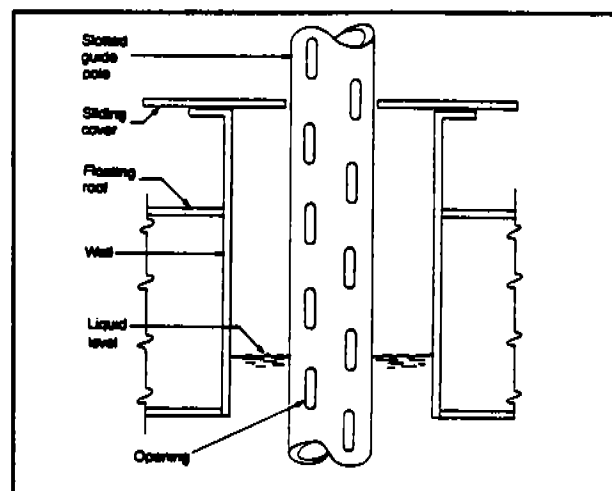
d. Slotted guide pole/sample well
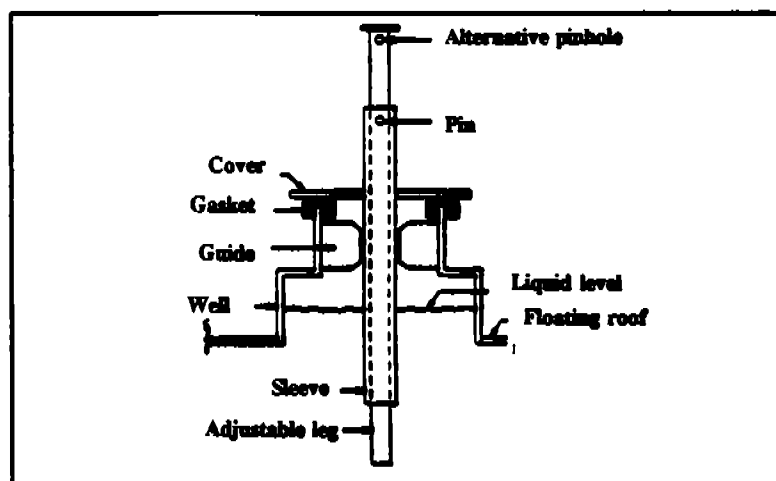
e. Vacuum breaker

Figure 12.2-5. Roof fittings for external floating roof tanks.[3]

12.2.3 Internal Floating Roof Tanks[4,5]

Total emissions from internal floating roof tanks are the sum of withdrawal losses and standing storage losses. Withdrawal losses occur in the same manner as in external floating roof tanks: as the floating roof lowers, some liquid remains attached to the tank surface and evaporates. Also, in internal floating roof tanks that have a column-supported fixed roof, some liquid clings to the columns. Standing storage losses from internal floating roof tanks include rim seal, deck fitting, and deck seam losses. The loss mechanisms described in Section 12.2.2 for external floating roof rim seal and roof fitting losses also apply to internal floating roofs. However, unlike external floating roof tanks in which wind is the predominant factor affecting rim seal loss, no dominant wind loss mechanism has been identified for internal floating roof tank rim seal losses. Deck seams in internal floating roof tanks are a source of emissions to the extent that these seams may not be completely vapor tight. The loss mechanisms described in Section 12.2.2 for external floating roof tank rim seals and roof fittings can describe internal floating roof deck seam losses. As with internal floating roof rim seal and roof fittings, the relative importance of each of the loss mechanisms is not known. It should be noted that welded internal floating roofs do not have deck seam losses.

Internal floating roofs typically incorporate one of two types of flexible, product-resistant seals: resilient foam-filled seals or wiper seals. Similar to those used on external floating roofs, each of these seals closes the annular vapor space between the edge of the floating roof and the tank shell to reduce evaporative losses. They are designed to compensate for small irregularities in the tank shell and allow the roof to move freely up and down in the tank without binding.

A resilient foam-filled seal used on an internal floating roof is similar in design to that described in Section 12.2.2 for external floating roofs. Two types of resilient foam-filled seals for internal floating roofs are shown in Figures 12.2-6a and 12.2-6b. These seals can be mounted either in contact with the liquid surface (liquid-mounted) or several centimeters above the liquid surface (vapor-mounted).

Resilient foam-filled seals work because of the expansion and contraction of a resilient material to maintain contact with the tank shell while accommodating varying annular rim space widths. These seals consist of a core of open-cell foam encapsulated in a coated fabric. The elasticity of the foam core pushes the fabric into contact with the tank shell. The seals are attached to a mounting on the deck perimeter and are continuous around the roof circumference. Polyurethane-coated nylon fabric and polyurethane foam are commonly used materials. For emission control, it is important that the mounting and radial seal joints be vapor-tight and that the seal be in substantial contact with the tank shell.

Wiper seals are commonly used as primary seals for internal floating roof tanks. This type of seal is depicted in Figure 12.2-6c. New tanks with wiper seals may have dual wipers, one mounted above the other.

Wiper seals generally consist of a continuous annular blade of flexible material fastened to a mounting bracket on the deck perimeter that spans the annular rim space and contacts the tank shell. The mounting is such that the blade is flexed, and its elasticity provides a sealing pressure against the tank shell. Such seals are vapor-mounted; a vapor space exists between the liquid stock and the bottom of the seal. For emission control, it is important that the mounting be vapor-tight, that the seal be continuous around the circumference of the roof, and that the blade be in substantial contact with the tank shell.

Two types of materials are commonly used to make the wipers. One type consists of a cellular, elastomeric material tapered in cross section with the thicker portion at the mounting. Buna-N rubber is a commonly used material. All radial joints in the blade are joined.

A second type of wiper seal construction uses a foam core wrapped with a coated fabric. Polyurethane on nylon fabric and polyurethane foam are common materials. The core provides the flexibility and support, while the fabric provides the vapor barrier and wear surface.

Secondary seals may be used to provide some additional evaporative loss control over that achieved by the primary seal. The secondary seal is mounted to an extended vertical rim plate, above the primary seal, as shown in Figure 12.2-7. Secondary seals can be either a resilient foam-filled seal or an elastomeric wiper seal, as previously described. For a given roof design, using a secondary seal further limits the operating capacity of a tank due to the need to keep the seal from interfering with the fixed-roof rafters when the tank is filled.

Numerous deck fittings penetrate or are attached to an internal floating roof. These fittings accommodate structural support members or allow for operational functions. The fittings can be a source of evaporative loss in that they require penetrations in the deck. Other accessories are used that do not penetrate the deck and are not, therefore, sources of evaporative loss. The most common fittings relevant to controlling vapor losses are described in the following paragraphs.

The access hatches, guide-pole wells, roof legs, vacuum breakers, and automatic gauge float wells for internal floating roofs are similar fittings to those already described for external floating roofs. Other fittings used on internal floating roof tanks include column wells, ladder wells, and stub drains.

1. Column wells. The most common fixed-roof designs are normally supported from inside the tank by means of vertical columns, which necessarily penetrate an internal floating deck. (Some fixed roofs are entirely self-supporting and, therefore, have no support columns.) Column wells are similar to unslotted guide pole wells on external floating roofs. Columns are made of pipe with circular cross sections or of structural shapes with irregular cross sections (built-up). The number of columns varies with tank diameter from a minimum of 1 to over 50 for very large tanks.

The columns pass through deck openings via peripheral vertical wells. With noncontact decks, the well should extend down into the liquid stock. Generally, a closure device exists between the top of the well and the column. Several proprietary designs exist for this closure, including sliding covers and fabric sleeves, which must accommodate the movements of the deck relative to the column as the liquid level changes. A sliding cover rests on the upper rim of the column well (which is normally fixed to the roof) and bridges the gap or space between the column well and the column. The cover, which has a cutout, or opening, around the column slides vertically relative to the column as the roof raises and lowers. At the same time, the cover slides horizontally relative to the rim of the well, which is fixed to the roof. A gasket around the rim of the well reduces emissions from this fitting. A flexible fabric sleeve seal between the rim of the well and the column (with a cutout or opening, to allow vertical motion of the seal relative to the columns) similarly accommodates limited horizontal motion of the roof relative to the column. A third design combines the advantages of the flexible fabric sleeve seal with a well that excludes all but a small portion of the liquid surface from direct exchange with the vapor space above the floating roof.

2. Ladder wells. Some tanks are equipped with internal ladders that extend from a manhole in the fixed roof to the tank bottom. The deck opening through which the ladder passes is constructed with similar design details and considerations to deck openings for column wells, as previously discussed.

3. Stub drains. Bolted internal floating roof decks are typically equipped with stub drains to allow any stored product that may be on the deck surface to drain back to the underside of the deck. The drains are attached so that they are flush with the upper deck. Stub drains are approximately 1 inch in diameter and extend down into the product on noncontact decks.
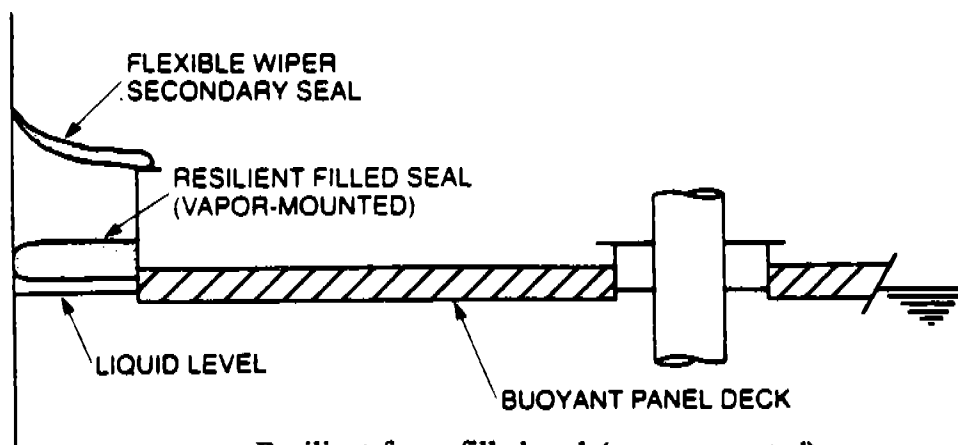
a. Resilient foam-filled seal (vapor-mounted).
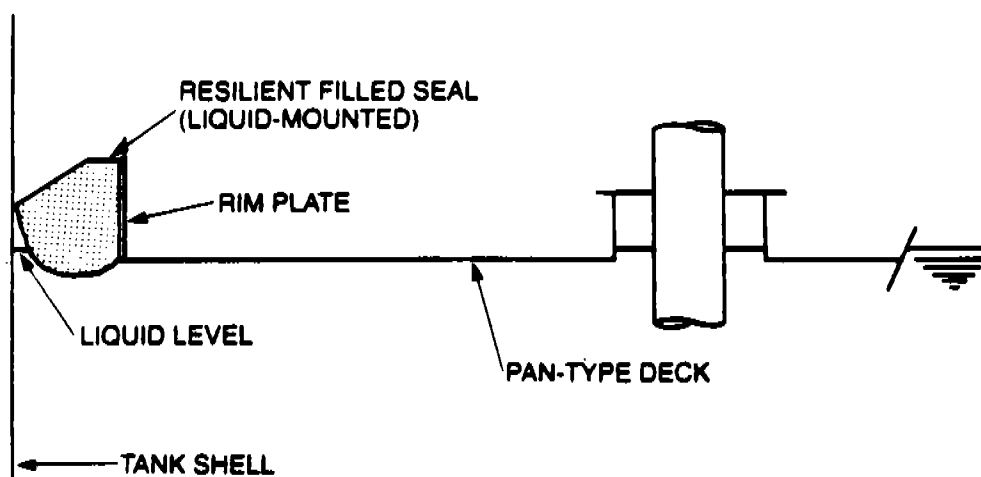
b. Resilient foam-filled seal (liquid-mounted).
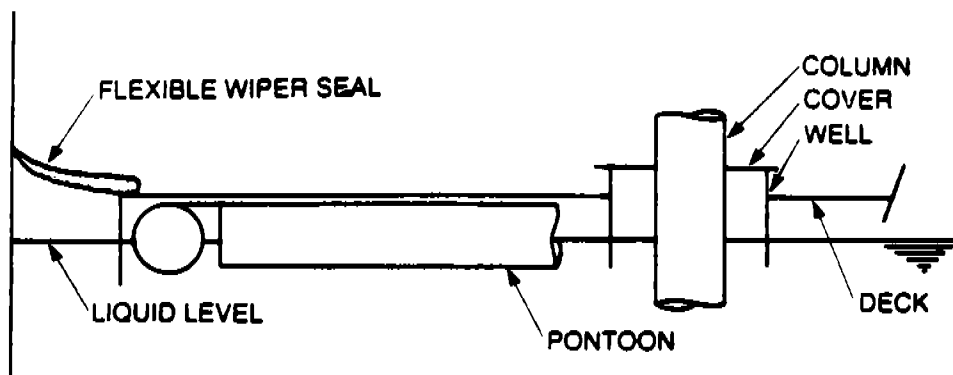
c. Elastomeric wiper seal.

Figure 12.2-6. Typical floatation devices and perimeter
seals for internal floating roofs.[4]
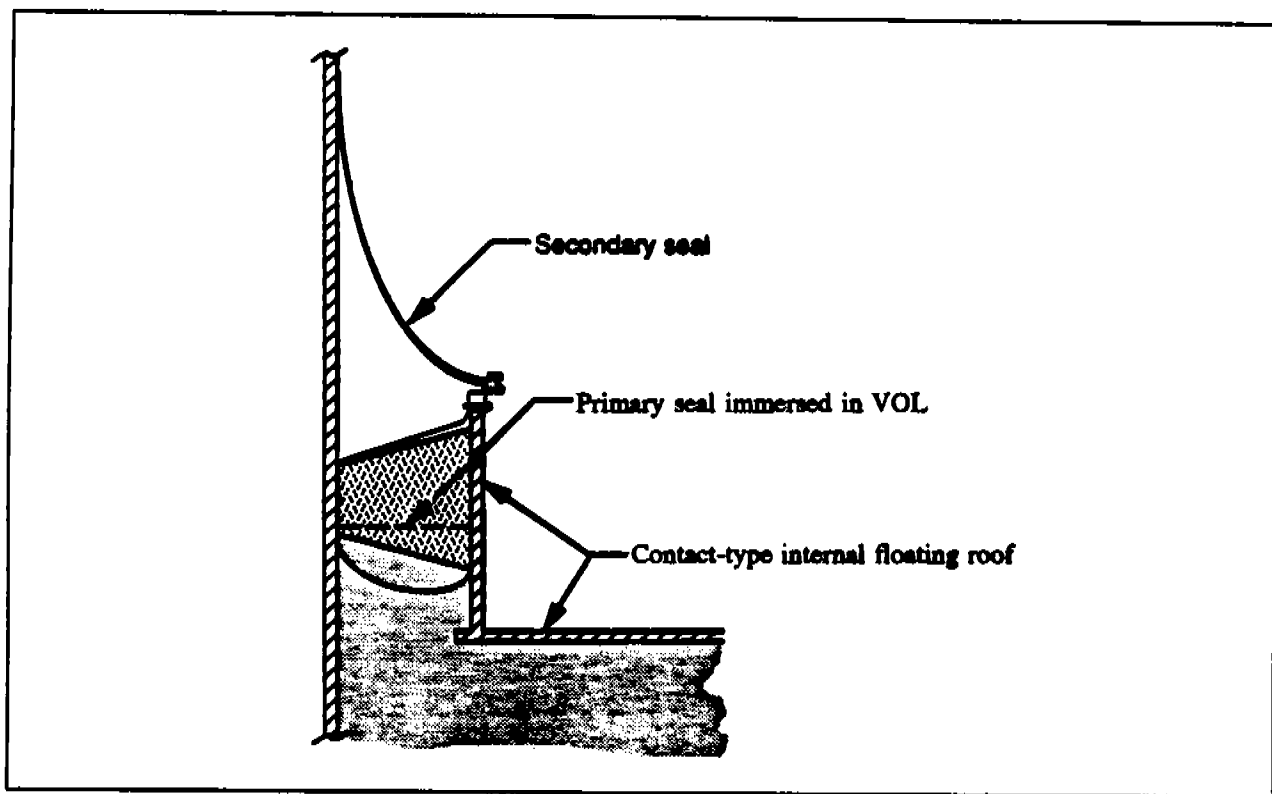
Figure 12.2-7. Rim-mounted secondary seal on an internal floating roof.[5]

12.3 EMISSION ESTIMATION PROCEDURES

The following section presents the emission estimation procedures for fixed roof, external floating roof, and internal floating roof tanks. These procedures are valid for all petroleum liquids, pure volatile organic liquids, and chemical mixtures with similar true vapor pressures. It is important to note that in all the emission estimation procedures the physical properties of the vapor do not include the noncondensibles (e.g., air) in the gas but only refer to the condensible components of the stored liquid. To aid in the emission estimation procedures, a list of variables with their corresponding definitions was developed and is presented in Table 12.3-1.

The factors presented in AP-42 are those that are currently available and have been reviewed and approved by the U. S. Environmental Protection Agency. As storage tank equipment vendors design new floating decks and equipment, new emission factors may be developed based on that equipment. If the new emission factors are reviewed and approved, the emission factors will be added to AP-42 during the next update.

The emission estimation procedures outlined in this chapter have been used as the basis for the development of a software program to estimate emissions from storage tanks. The software program entitled "TANKS" is available through the Bulletin Board System maintained by the U. S. Environmental Protection Agency.

12.3.1 Total Losses From Fixed Roof Tanks[4,6-12]

The following equations, provided to estimate standing storage and working loss emissions, apply to tanks with vertical cylindrical shells and fixed roofs. These tanks must be substantially liquid- and vapor-tight and must operate approximately at atmospheric pressure. Total losses from fixed roof tanks are equal to the sum of the standing storage loss and working loss:

$$L_T = L_S + L_W \tag{1-1}$$

where:

L_T = total losses, lb/yr

L_S = standing storage losses, lb/yr

L_W = working losses, lb/yr

Standing Storage Loss - Fixed roof tank breathing or standing storage losses can be estimated from:

$$L_S = 365 \, V_V W_V K_E K_S \qquad (1\text{-}2)$$

where:

L_S = standing storage loss, lb/yr

V_V = vapor space volume, ft^3

W_V = vapor density, lb/ft^3

K_E = vapor space expansion factor, dimensionless

K_S = vented vapor saturation factor, dimensionless

365 = constant, days/year

Tank Vapor Space Volume, V_V - The tank vapor space volume is calculated using the following equation:

$$V_V = \frac{\pi}{4} D^2 H_{VO} \qquad (1\text{-}3)$$

where:

V_V = vapor space volume, ft^3

D = tank diameter, ft, see Note 1 for horizontal tanks

H_{VO} = vapor space outage, ft

The vapor space outage, H_{VO} is the height of a cylinder of tank diameter, D, whose volume is equivalent to the vapor space volume of a fixed roof tank, including the volume under the cone or dome roof. The vapor space outage, H_{VO}, is estimated from:

$$H_{VO} = H_S - H_L + H_{RO} \qquad (1\text{-}4)$$

where:

H_{VO} = vapor space outage, ft

H_S = tank shell height, ft

H_L = liquid height, ft

H_{RO} = roof outage, ft; see Note 2 for a cone roof or Note 3 for a dome roof

Notes:

1. The emission estimating equations presented above were developed for vertical fixed roof tanks. If a user needs to estimate emissions from a horizontal fixed roof tank, some of the tank parameters can be modified before using the vertical tank emission estimating equations. First, by assuming that the tank is one-half filled, the surface area of the liquid in the tank is approximately equal to the length of the tank times the diameter of the tank. Next, assume that this area represents a circle, i.e., that the liquid is an upright cylinder. Therefore, the effective diameter, D_E, is then equal to:

$$D_E = \sqrt{\frac{LD}{0.785}} \qquad (1\text{-}5)$$

where:

D_E = effective tank diameter, ft

L = length of tank, ft

D = actual diameter of tank, ft

One-half of the actual diameter of the horizontal tank should be used as the vapor space outage, H_{VO}. This method yields only a very approximate value for emissions from horizontal storage tanks. For underground horizontal tanks, assume that no breathing or standing storage losses occur ($L_S = 0$) because the insulating nature of the earth limits the diurnal temperature change. No modifications to the working loss equation are necessary for either above-ground or underground horizontal tanks.

2. For a cone roof, the roof outage, H_{RO}, is calculated as follows:

$$H_{RO} = 1/3 \ H_R \qquad (1\text{-}6)$$

where:

H_{RO} = roof outage (or shell height equivalent to the volume contained under the roof), ft

H_R = tank roof height, ft

The tank roof height, H_R, is equal to $S_R R_S$

where,

S_R = tank cone roof slope, if unknown, a standard value of 0.0625 ft/ft is used, ft/ft

R_S = tank shell radius, ft

3. For a dome roof, the roof outage, H_{RO}, is calculated as follows:

$$H_{RO} = H_R \left[1/2 + 1/6 \left[\frac{H_R}{R_S} \right]^2 \right] \qquad (1\text{-}7)$$

where:

H_{RO} = roof outage, ft

H_R = tank roof height, ft

R_S = tank shell radius, ft

The tank roof height, H_R, is calculated:

$$H_R = R_R - (R_R^2 - R_S^2)^{0.5} \qquad (1\text{-}8)$$

where:

H_R = tank roof height, ft

R_R = tank dome roof radius, ft

R_S = tank shell radius, ft

The value of R_R usually ranges from 0.8D - 1.2D. If R_R is unknown, the tank diameter is used in its place. If the tank diameter is used as the value for R_R, Equations 1-7 and 1-8 reduce to $H_R = 0.268 \, R_S$ and $H_{RO} = 0.137 \, R_S$.

<u>Vapor Density, W_V</u> - The density of vapor is calculated using the following equation:

$$W_V = \frac{M_V P_{VA}}{RT_{LA}} \qquad (1-9)$$

where:

W_V = vapor density, lb/ft^3

M_V = vapor molecular weight, lb/lb-mole; see Note 1

R = the ideal gas constant, 10.731 psia•ft^3/lb-mole•°R

P_{VA} = vapor pressure at daily average liquid surface temperature, psia; see Notes 1 and 2

T_{LA} = daily average liquid surface temperature, °R; see Note 3

Notes:

1. The molecular weight of the vapor, M_V, can be determined from Table 12.3-2 and Table 12.3-3 for selected petroleum liquids and volatile organic liquids, respectively, or by analyzing vapor samples. Where mixtures of organic liquids are stored in a tank, M_V can be calculated from the liquid composition. The molecular weight of the vapor, M_V, is equal to the sum of the molecular weight, M_i, multiplied by the <u>vapor</u> mole fraction, y_i, for each component. The <u>vapor</u> mole fraction is equal to the partial pressure of component i divided by the total vapor pressure. The partial pressure of component i is equal to the true vapor pressure of component i (P) multiplied by the <u>liquid</u> mole fraction, (x_i). Therefore,

$$M_V = \Sigma M_i y_i = \Sigma M_i \left(\frac{Px_i}{P_{VA}}\right) \qquad (1-10)$$

where: P_{VA}, total vapor pressure of the stored liquid, by Raoult's law, is:

$$P_{VA} = \Sigma Px_i \qquad (1-11)$$

For more detailed information, please refer to Section 12.4.

2. True vapor pressure is the equilibrium partial pressure exerted by a volatile organic liquid, as defined by ASTM-D 2879 or as obtained from standard reference texts. Reid vapor pressure is the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids, except liquified petroleum gases, as determined by ASTM-D-323. True vapor pressures for organic liquids can be determined from Table 12.3-3. True vapor pressure can be determined for crude oils using Figures 12.3-1A and 12.3-1B. For refined

stocks (gasolines and naphthas), Table 12.3-2 or Figures 12.3-2A and 12-3-2B can be used. In order to use Figures 12.3-1A, 12.3-1B, 12.3-2A, or 12.3-2B, the stored liquid surface temperature, T_{LA}, must be determined in degrees Fahrenheit. See Note 3 to determine T_{LA}.

Alternatively, true vapor pressure for selected petroleum liquid stocks, at the stored liquid surface temperature, can be determined using the following equation:

$$P_{VA} = exp [A - (B/T_{LA})] \qquad (1\text{-}12a)$$

where:

exp = exponential function

A = constant in the vapor pressure equation, dimensionless

B = constant in the vapor pressure equation, °R

T_{LA} = daily average liquid surface temperature, °R

P_{VA} = true vapor pressure, psia

For selected petroleum liquid stocks, values for the constants A and B are listed in Table 12.3-2. For refined petroleum stocks, the constants A and B can be calculated from the equations presented in Figure 12.3-3 and the distillation slopes presented in Table 12.3-4. For crude oil stocks, the constants A and B can be calculated from the equations presented in Figure 12.3-4. Note that in Equation 1-12, T_{LA} is determined in degrees Rankine instead of degrees Fahrenheit.

The true vapor pressure of organic liquids at the stored liquid temperature can be estimated by Antoines equation:

$$\log P_{VA} = A - \frac{B}{T_{LA} + C} \qquad (1\text{-}12b)$$

where:

A = constant in vapor pressure equation

B = constant in vapor pressure equation

C = constant in vapor pressure equation

T_{LA} = average liquid surface temperature, °C

P_{VA} = vapor pressure at average liquid surface temperature, mm Hg

For organic liquids, the values for the constants A, B, and C are listed in Table 12.3-5. Note that in equation 1-12b, T_{LA} is determined in degrees Celsius instead of degrees Rankine. Also, in equation 1-12b, P_{VA} is determined in mm of Hg rather than psia (760 mm Hg = 14.696 psia).

3. If the daily average liquid surface temperature, T_{LA}, is unknown, it is calculated using the following equation:

$$T_{LA} = 0.44T_{AA} + 0.56T_B + 0.0079\ \alpha I \qquad (1\text{-}13)$$

where:

$\qquad T_{LA}$ = daily average liquid surface temperature, °R

$\qquad T_{AA}$ = daily average ambient temperature, °R; see Note 4

$\qquad T_B$ = liquid bulk temperature, °R; see Note 5

$\qquad \alpha$ = tank paint solar absorptance, dimensionless; see Table 12.3-7

$\qquad I$ = daily total solar insolation factor, Btu/ft^2•day; see Table 12.3-6

If T_{LA} is used to calculate P_{VA} from Figures 12.3.1A through 12.3.2B, T_{LA} must be converted from degrees Rankine to degrees Fahrenheit (°F = °R - 460). If T_{LA} is used to calculate P_{VA} from Equation 1-12b, T_{LA} must be converted from degrees Rankine to degrees Celsius (°C = (°R - 492)/1.8). Equation 1-13 should not be used to estimate emissions from insulated tanks. In the case of insulated tanks, the average liquid surface temperature should be based on liquid surface temperature measurements from the tank.

4. The daily average ambient temperature, T_{AA}, is calculated using the following equation:

$$T_{AA} = (T_{AX} + T_{AN})/2 \qquad (1\text{-}14)$$

where:

$\qquad T_{AA}$ = daily average ambient temperature, °R

$\qquad T_{AX}$ = daily maximum ambient temperature, °R

$\qquad T_{AN}$ = daily minimum ambient temperature, °R

$\qquad$ Table 12.3-6 gives values of T_{AX} and T_{AN} for select U.S. cities.

5. The liquid bulk temperature, T_B, is calculated using the following equation:

$$T_B = T_{AA} + 6\alpha - 1 \qquad (1\text{-}15)$$

where:

T_B = liquid bulk temperature, °R

T_{AA} = daily average ambient temperature, °R, as calculated in Note 4

α = tank paint solar absorptance, dimensionless; see Table 12.3-7.

<u>Vapor Space Expansion Factor, K_E</u> - The vapor space expansion factor, K_E, is calculated using the following equation:

$$K_E = \frac{\Delta T_V}{T_{LA}} + \frac{\Delta P_V - \Delta P_B}{P_A - P_{VA}} \qquad (1\text{-}16)$$

where:

ΔT_V = daily vapor temperature range, °R; see Note 1

ΔP_V = daily vapor pressure range, psi; see Note 2

ΔP_B = breather vent pressure setting range, psi; see Note 3

P_A = atmospheric pressure, 14.7 psia

P_{VA} = vapor pressure at daily average liquid surface temperature, psia; see Notes 1 and 2 for Equation 1-9

T_{LA} = daily average liquid surface temperature, °R; see Note 3 for Equation 1-9

Notes:

1. The daily vapor temperature range ΔT_V, is calculated using the following equation:

$$\Delta T_V = 0.72 \, \Delta T_A + 0.028 \, \alpha I \qquad (1\text{-}17)$$

where:

ΔT_V = daily vapor temperature range, °R

ΔT_A = daily ambient temperature range, °R; see Note 4

α = tank paint solar absorptance, dimensionless; see Table 12.3-7

I = daily total solar insolation factor, Btu/ft^2•day; see Table 12.3-6

2. The daily vapor pressure range, ΔP_V, can be calculated using the following equation:

$$\Delta P_V = P_{VX} - P_{VN} \tag{1-18}$$

where:

ΔP_V = daily vapor pressure range, psia

P_{VX} = vapor pressure at the daily maximum liquid surface temperature, psia; see Note 5

P_{VN} = vapor pressure at the daily minimum liquid surface temperature, psia; see Note 5

The following method can be used as an alternate means of calculating ΔP_V for petroleum liquids:

$$\Delta P_V = \frac{0.50\, B\, P_{VA}\, \Delta T_V}{T_{LA}^2} \tag{1-19}$$

where:

ΔP_V = daily vapor pressure range, psia

B = constant in the vapor pressure equation, °R; see Note 2 to Equation 1-9

P_{VA} = vapor pressure at the daily average liquid surface temperature, psia; see Notes 1 and 2 to Equation 1-9

T_{LA} = daily average liquid surface temperature, °R; see Note 3 to Equation 1-9

ΔT_V = daily vapor temperature range, °R; see Note 1

3. The breather vent pressure setting range, ΔP_B, is calculated using the following equation:

$$\Delta P_B = P_{BP} - P_{BV} \tag{1-20}$$

where:

ΔP_B = breather vent pressure setting range, psig

P_{BP} = breather vent pressure setting, psig

P_{BV} = breather vent vacuum setting, psig

If specific information on the breather vent pressure setting and vacuum setting is not available, assume 0.03 psig for P_{BP} and -0.03 psig for P_{BV} as typical values. If the fixed roof tank is of bolted or riveted construction in which the roof or shell plates are not vapor tight, assume that $\Delta P_B = 0$, even if a breather vent is used. The estimating equations for fixed roof tanks do not apply to either low or high pressure tanks. If the breather vent pressure or vacuum setting exceeds 1.0 psig, the standing storage losses could potentially be negative.

4. The daily ambient temperature range, ΔT_A, is calculated using the following equation:

$$\Delta T_A = T_{AX} - T_{AN} \qquad (1\text{-}21)$$

where:

ΔT_A = daily ambient temperature range, °R

T_{AX} = daily maximum ambient temperature, °R

T_{AN} = daily minimum ambient temperature, °R

Table 12.3-6 gives values of T_{AX} and T_{AN} for select cities in the United States.[11]

5. The vapor pressures associated with daily maximum and minimum liquid surface temperature, P_{VX} and P_{VN}, respectively are calculated by substituting the corresponding temperatures, T_{LX} and T_{LN} into the pressure function discussed in Notes 1 and 2 to Equation 1-9. If T_{LX} and T_{LN} are unknown, Figure 12.3-5 can be used to calculate their values.

Vented Vapor Saturation Factor, K_S - The vented vapor saturation factor, K_S, is calculated using the following equation:

$$K_S = \frac{1}{1 + 0.053 P_{VA} H_{VO}} \qquad (1\text{-}22)$$

where:

K_S = vented vapor saturation factor, dimensionless

P_{VA} = vapor pressure at daily average liquid surface temperature, psia; see Notes 1 and 2 to Equation 1-9

H_{VO} = vapor space outage, ft, as calculated in Equation 1-4

<u>Working Loss</u> - The working loss, L_W, can be estimated from:

$$L_W = 0.0010 \, M_V P_{VA} Q K_N K_P, \qquad (1\text{-}23)$$

where:

L_W = working losses, lb/yr

M_V = vapor molecular weight, lb/lb-mole; see Note 1 to Equation 1-9

P_{VA} = vapor pressure at daily average liquid surface temperature, psia; see Notes 1 and 2 to Equation 1-9

Q = annual net throughput, bbl/yr

K_N = turnover factor, dimensionless; see Figure 12.3-6
for turnovers > 36, $K_N = (180 + N)/6N$
for turnovers ≤ 36, $K_N = 1$

N = number of turnovers per year, dimensionless

$$N = \frac{5.614 \, Q}{V_{LX}} \qquad (1\text{-}24)$$

where:

N = number of turnovers per year, dimensionless

Q = annual net throughput, bbl/yr

V_{LX} = tank maximum liquid volume, ft^3

$$V_{LX} = \frac{\pi}{4} D^2 H_{LX} \qquad (1\text{-}25)$$

where:

D = diameter, ft

H_{LX} = maximum liquid height, ft

K_P = working loss product factor, dimensionless, 0.75 for crude oils. For all other organic liquids, $K_P = 1$
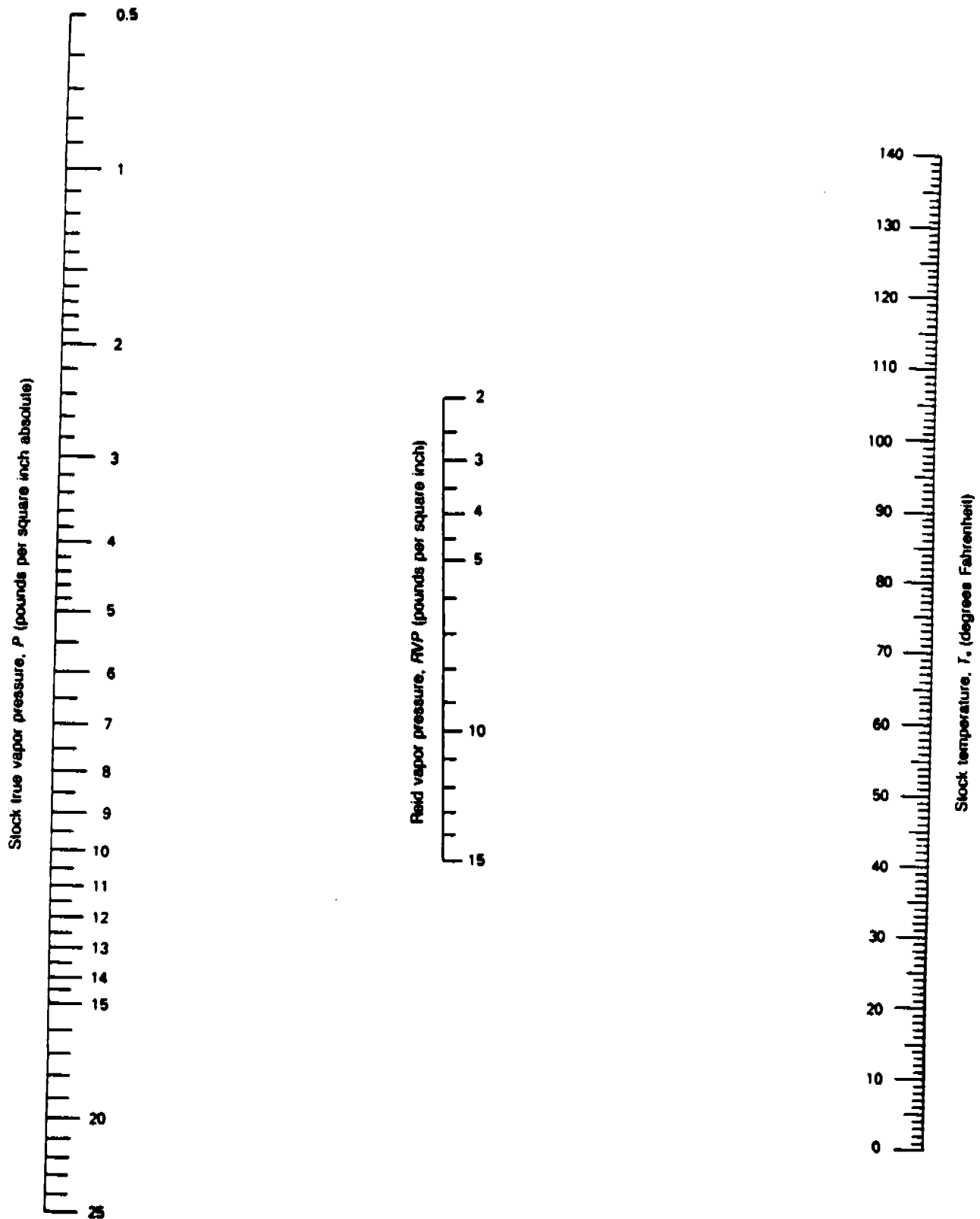
Figure 12.3-1A. True vapor pressure of crude oils with a
Reid vapor pressure of 2 to 15 pounds per square inch.[4]

EMISSION FACTORS
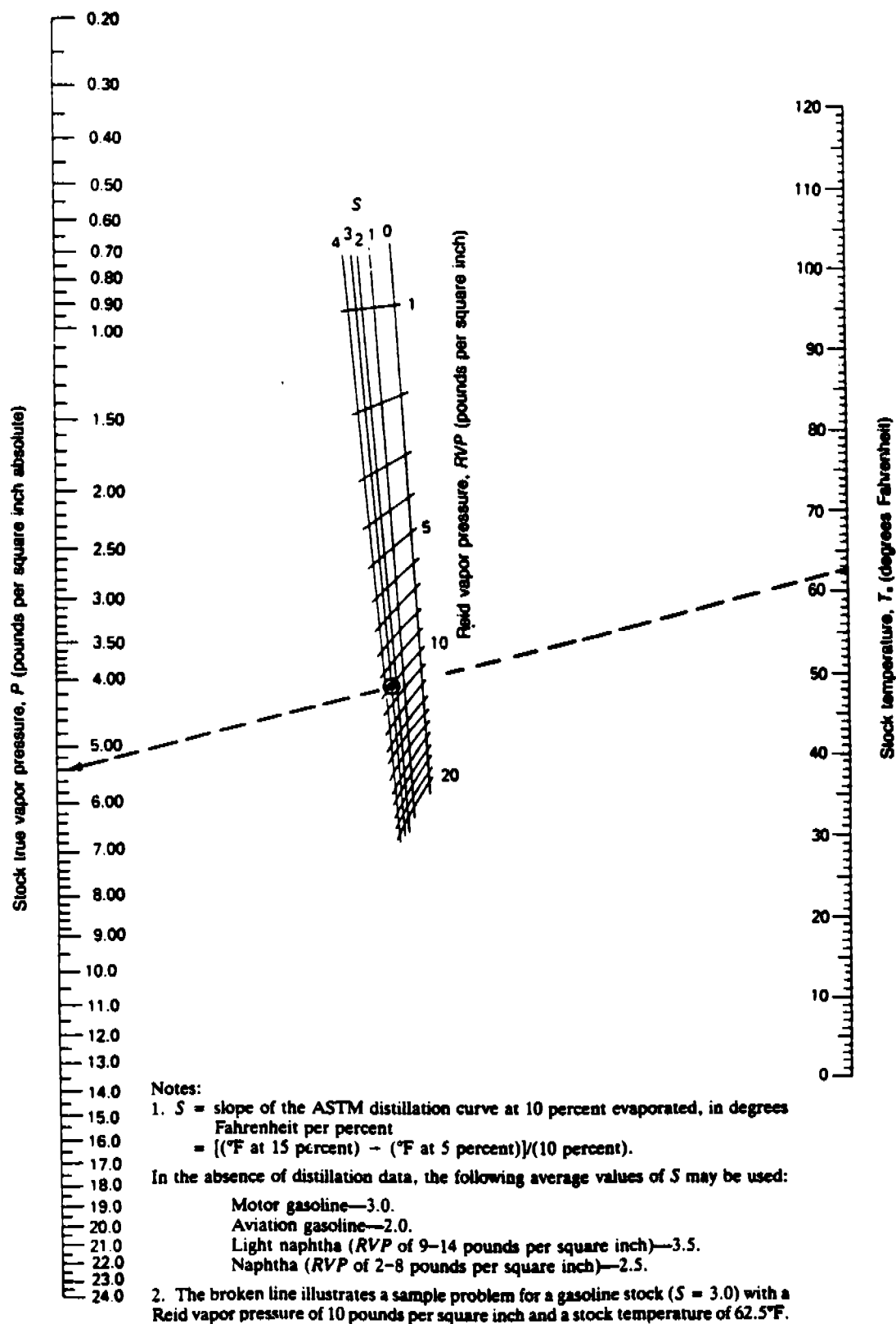
Figure 12.3-2A. True vapor pressure of refined petroleum stocks with a Reid vapor pressure of 1 to 20 pounds per square inch.[4]

Notes:
1. S = slope of the ASTM distillation curve at 10 percent evaporated, in degrees Fahrenheit per percent
   = [(°F at 15 percent) − (°F at 5 percent)]/(10 percent).

In the absence of distillation data, the following average values of S may be used:

Motor gasoline—3.0.
Aviation gasoline—2.0.
Light naphtha (RVP of 9–14 pounds per square inch)—3.5.
Naphtha (RVP of 2–8 pounds per square inch)—2.5.

2. The broken line illustrates a sample problem for a gasoline stock (S = 3.0) with a Reid vapor pressure of 10 pounds per square inch and a stock temperature of 62.5°F.

$$P = \exp\left\{\left[\left(\frac{2799}{T + 459.6}\right) - 2.227\right]\log_{10}(RVP) - \left(\frac{7261}{T + 459.6}\right) + 12.82\right\}$$

Where:

P = stock true vapor pressure, in pounds per square inch absolute.
T = stock temperature, in degrees Fahrenheit.
RVP = Reid vapor pressure, in pounds per square inch.

Note: This equation was derived from a regression analysis of points read off Figure 12.3-1A over the full range of Reid vapor pressure slopes of the ASTM distillation curve at 10 percent evaporated, and stock temperatures. In general, the equation yields P values that are within +0.05 pound per square inch absolute of the values obtained directly from the nomograph.

Figure 12.3-1B. Equation for true vapor pressure of crude oils with a Reid vapor pressure of 2 to 15 pounds per square inch.[4]

$$P = \exp\left\{\left[0.7553 - \left(\frac{413.0}{T + 459.6}\right)\right]S^{0.5}\log_{10}(RVP) - \left[1.854 - \left(\frac{1042}{T + 459.6}\right)\right]S^{0.5}\right.$$
$$\left. + \left[\left(\frac{2416}{T + 459.6}\right) - 2.013\right]\log_{10}(RVP) - \left(\frac{8742}{T + 459.6}\right) + 15.64\right\}$$

Where:

P = stock true vapor pressure, in pounds per square inch absolute.
T = stock temperature, in degrees Fahrenheit.
RVP = Reid vapor pressure, in pounds per square inch.
S = slope of the ASTM distillation curve at 10 percent evaporated, in degrees Fahrenheit per percent.

Note: This equation was derived from a regression analysis of points read off Figure 12.3-2A over the full range of Reid vapor pressure slopes of the ASTM distillation curve at 10 percent evaporated, and stock temperatures. In general, the equation yields P values that are within +0.05 pound per square inch absolute of the values obtained directly from the nomograph.

Figure 12.3-2B. Equation for true vapor pressure of refined petroleum stocks with a Reid vapor pressure of 1 to 20 pounds per square inch.[4]

$A = 15.64 - 1.854\ S^{0.5} - (0.8742 - 0.3280\ S^{0.5})\ln(RVP)$
$B = 8,742 - 1,042\ S^{0.5} - (1,049 - 179.4\ S^{0.5})\ln(RVP)$
where:

RVP = stock Reid vapor pressure, psi

$\ln$ = natural logarithm function

S = stock ASTM-D86 distillation slope at 10 volume percent evaporation (°F/vol %)

Figure 12.3-3. Equations to determine vapor pressure constants A and B for refined petroleum stocks.[6]

$$A = 12.82 - 0.9672 \ln (RVP)$$

$$B = 7,261 - 1,216 \ln (RVP)$$

where:

$$RVP = \text{stock Reid vapor pressure, psi}$$

$$\ln = \text{natural logarithm function}$$

Figure 12.3-4. Equations to determine vapor pressure Constants A and B for crude oils stocks.[6]

Daily Maximum and Minimum Liquid Surface Temperature, (°R)

$$T_{LX} = T_{LA} + 0.25\, \Delta T_V$$

$$T_{LN} = T_{LA} - 0.25\, \Delta T_V$$

where:

T_{LX} = daily maximum liquid surface temperature, °R

T_{LA} is as defined in Note 3 to Equation 1-9

ΔT_V is as defined in Note 1 to Equation 1-16

T_{LN} = daily minimum liquid surface temperature, °R

Figure 12.3-5. Equations for the daily maximum and minimum liquid surface temperatures.[6]
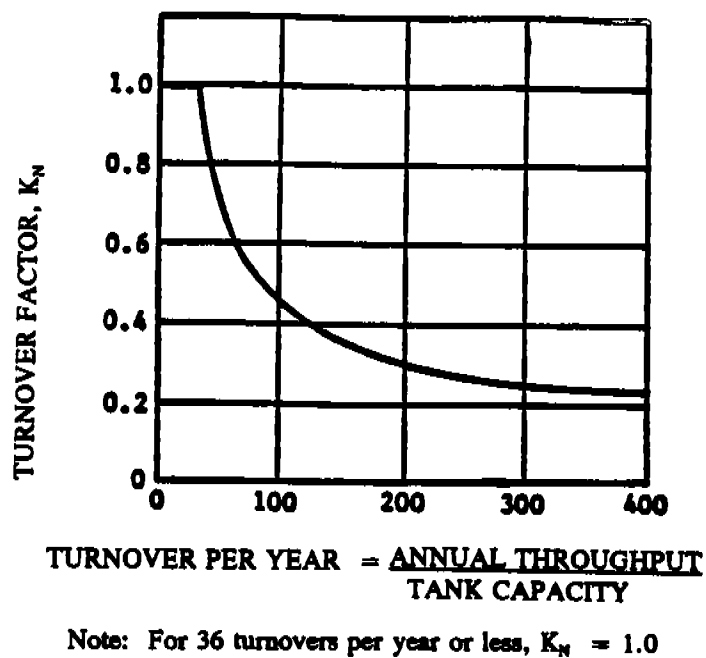
Figure 12.3-6. Turnover factor (K_N) for fixed roof tanks.[6]

TABLE 12.3-1. LIST OF ABBREVIATIONS USED IN THE TANK EQUATIONS

Variable	Description	Variable	Description	Variable	Description
L_T	total losses, lb/yr	P	true vapor pressure of component i, psia	P_{BP}	breather vent pressure setting, psig
L_S	standing storage losses, lb/yr	A	constant in vapor pressure equation, dimensionless	P_{BV}	breather vent vacuum setting, psig
L_W	working losses, lb/yr	B	constant in vapor pressure equation, °R	Q	annual net throughput, bbl/yr
V_V	vapor space volume, ft³			K_N	turnover factor, dimensionless
W_V	vapor density, lb/ft³	T_{AA}	daily average ambient temperature, °R	N	number of turnovers per year, dimensionless
K_E	vapor space expansion factor, dimensionless	T_B	liquid bulk temperature, °R	π	constant, (3.14159)
K_S	vented vapor saturation factor, dimensionless	α	tank paint solar absorptance, dimensionless	V_{LX}	tank maximum liquid volume, ft³
D	tank diameter, ft	I	daily total solar insolation factor, Btu/ft²•day	H_{LX}	maximum liquid height, ft
H_{VO}	vapor space outage, ft			K_P	working loss product factor for fixed roof tanks, dimensionless
H_S	tank shell height, ft	T_{AX}	daily maximum ambient temperature, °R	L_R	rim seal loss, lb/yr
H_L	liquid height, ft	T_{AN}	daily minimum ambient temperature, °R	L_{WD}	withdrawal loss, lb/yr
H_{RO}	roof outage, ft			L_F	roof fitting loss, lb/yr
H_R	tank roof height, ft	D_E	effective tank diameter, ft	K_R	seal factor, lb-mole/mph^n•ft•yr for external floating roof tanks or lb-mole/ft•yr for internal floating roof tanks
S_R	tank cone roof slope, ft/ft	L	length of tank, ft		
R_S	tank shell radius, ft	ΔT_V	daily vapor temperature range, °R		
R_R	tank dome roof radius, ft			v	average wind speed, mph
M_V	vapor molecular weight, lb/lb-mole	ΔP_V	daily vapor pressure range, psi	n	seal-related speed exponent, dimensionless
R	ideal gas constant, (10.731 psia • ft³/lb-mole•°R)	ΔP_B	breather vent pressure setting range, psig	P^*	vapor pressure function, dimensionless
P_{VA}	vapor pressure at daily average liquid surface temperature, psia	P_A	atmospheric pressure, psia	F_R	rim seal loss factor, lb-moles/ft•yr
		ΔT_A	daily ambient temperature range, °R		
T_{LA}	daily average liquid surface temperature, °R	P_{VX}	vapor pressure at the daily maximum liquid surface temperature, psia	K_C	product factor for floating roof tanks, dimensionless
M_i	molecular weight of component i, lb/lb-mole			C	shell clingage factor, bbl/1,000 ft²
y_i	vapor mole fraction of component i, lb-mole/lb-mole	P_{VN}	vapor pressure at the daily minimum liquid surface temperature, psia	W_L	average organic liquid density, lb/gal
x_i	liquid mole fraction of component i, lb-mole/lb-mole			F_F	total roof fitting loss factor, lb-mole/yr

TABLE 12.3-1. (Continued)

Variable	Description	Variable	Description
N_{Fi}	number of roof fittings of a particular type, dimensionless	V_1	volume of liquid pumped into system, bbl/yr
n_f	total number of different types of fittings, dimensionless	V_2	volume expansion capacity, bbl
K_{Fi}	loss factor for a particular type of roof fitting, lb-mole/yr	N_2	number of transfers into system, dimensionless
K_{Fai}	loss factor for a particular type of roof fitting, lb-mole/yr		
K_{Fbi}	loss factor for a particular type of roof fitting, lb-mole/mph^m·yr)		
m_i	loss factor for a particular type of roof fitting, dimensionless		
i	1,2,.....η, dimensionless		
L_p	deck seam loss, lb/yr		
N_C	number of columns, dimensionless		
F_C	effective column diameter, ft		
K_D	deck seam loss per unit seam length factor, lb-mol/ft-yr		
S_D	deck seam length factor, ft/ft^2		
L_{seam}	total length of deck seam, ft		
A_{deck}	area of deck, ft^2		
P_i	partial pressure of component i, psia		
$Z_{i,L}$	liquid weight fraction of component i, lb/lb		
M_L	molecular weight of liquid mixture, lb/lb-mole		
$Z_{i,v}$	vapor weight fraction of component i, lb/lb		
N_{TOTAL}	total number of moles in mixtures, lb-mole		
W_i	liquid density of component i, lb/ft^3		
$L_{T,i}$	emission rate of component i, lb/yr		
L_v	variable vapor space filling loss, lb/1,000 gal throughput		

TABLE 12.3-2. PROPERTIES (M_V, W_{VC}, P_{VA}, W_L) OF SELECTED PETROLEUM LIQUIDS[a]

Petroleum liquid	Vapor molecular weight (at 60°F) M_V (lb/lb-mole)	Condensed vapor density (at 60°F) W_{VC} (lb/gal)	Liquid density, lb/gal at 60°F	True vapor pressure in psi at						
				40°C	50°F	60°F	70°F	80°F	90°F	100°F
Gasoline RVP 13	62	4.9	4.9	4.7	5.7	6.9	8.3	9.9	11.7	13.8
Gasoline RVP 10	66	5.1	5.1	3.4	5.7	5.2	6.2	7.4	8.8	10.5
Gasoline RVP 7	68	5.2	5.2	2.3	2.9	3.5	4.3	5.2	6.2	7.4
Crude Oil RVP 5	50	4.5	4.5	1.8	2.3	2.8	3.4	4.0	4.8	5.7
Jet naphtha (JP-4)	80	5.4	5.4	0.8	1.0	1.3	1.6	1.9	2.4	2.7
Jet kerosene	130	6.1	6.1	0.0041	0.0060	0.0085	0.011	0.015	0.021	0.029
Distillate fuel oil No. 2	130	6.1	6.1	0.0031	0.0045	0.0074	0.0090	0.012	0.016	0.022
Residual oil No. 6	190	6.4	6.4	0.00002	0.00003	0.00004	0.00006	0.00009	0.00013	0.00019

Notes:
[a]References 7 and 8.

Storage of Organic Liquids

TABLE 12.3-3. PHYSICAL PROPERTIES OF SELECTED PETROCHEMICALS[a]

Name	Formula	Molecular weight	Boiling point at 1 atmosphere (°F)	Liquid density at 60°F (pounds per gallon)	Vapor pressure (pounds per square inch absolute) at						
					40°F	50°F	60°F	70°F	80°F	90°F	100°F
Acetone	CH$_3$COCH$_3$	58.08	133.0	6.628	1.682	2.185	2.862	3.713	4.699	5.917	7.251
Acetonitrile	CH$_3$CN	41.05	178.9	6.558	0.638	0.831	1.083	1.412	1.876	2.456	3.133
Acrylonitrile	CH$_2$:CHCN	53.06	173.5	6.758	0.812	0.967	1.373	1.799	2.378	3.133	4.022
Allyl alcohol	CH$_2$:CHCH$_2$OH	58.08	206.6	7.125	0.135	0.193	0.261	0.387	0.522	0.716	1.006
Allyl chloride	CH$_2$:CHCH$_2$Cl	76.53	113.2	7.864	2.998	3.772	4.797	6.015	7.447	9.110	11.025
Ammonium hydroxide (28.8% solution)	NH$_4$OH-H$_2$O	35.05	83.0	7.481	5.130	6.630	8.480	10.760	13.520	16.760	20.680
Benzene	C$_6$H$_6$	78.11	176.2	7.365	0.638	0.870	1.160	1.508	1.972	2.610	3.287
iso-Butyl alcohol	(CH$_3$)$_2$CHCH$_2$OH	74.12	227.1	6.712	0.058	0.097	0.135	0.193	0.271	0.387	0.541
tert-Butyl alcohol	(CH$_3$)$_3$COH	74.12	180.5	6.595	0.174	0.290	0.425	0.638	0.909	1.238	1.702
n-Butyl chloride	CH$_3$CH$_2$CH$_2$CH$_2$Cl	92.57	172.0	7.430	0.715	1.006	1.320	1.740	2.185	2.684	3.481
Carbon disulfide	CS$_2$	76.13	115.3	10.588	3.036	3.867	4.834	6.014	7.387	9.185	11.215
Carbon tetrachloride	CCl$_4$	153.84	170.2	13.366	0.793	1.064	1.412	1.798	2.301	2.997	3.771
Chloroform	CHCl$_3$	119.39	142.7	12.488	1.528	1.934	2.475	3.191	4.061	5.163	6.342
Chloroprene	CH$_2$:CCl·CH:CH$_2$	88.54	138.9	8.046	1.760	2.320	2.901	3.655	4.563	5.685	6.981
Cyclohexane	C$_6$H$_{12}$	84.16	177.3	6.522	0.677	0.928	1.218	1.605	2.069	2.610	3.249
Cyclopentane	C$_5$H$_{10}$	70.13	120.7	6.248	2.514	3.287	4.177	5.240	6.517	8.063	9.668
1,1-Dichloroethane	CH$_3$CHCl$_2$	98.97	135.1	9.861	1.682	2.243	2.901	3.771	4.738	5.840	7.193
1,2-Dichloroethane	CH$_2$ClCH$_2$Cl	98.97	182.5	10.500	0.561	0.773	1.025	1.431	1.740	2.243	2.804
cis-1,2-Dichloroethylene	CHCl:CHCl	96.95	140.2	10.763	1.450	2.011	2.668	3.461	4.409	5.646	6.807
trans-1,2-Dichloroethylene	CHCl:CHCl	96.95	119.1	10.524	2.552	3.384	4.351	5.530	6.807	8.315	10.016
Diethylamine	(C$_2$H$_5$)$_2$NH	73.14	131.9	5.906	1.644	1.992	2.862	3.867	4.892	6.130	7.541
Diethyl ether	C$_2$H$_5$OC$_2$H$_5$	74.12	94.3	5.988	4.215	5.666	7.019	8.702	10.442	13.342	Boils
Di-iso-propyl ether	(CH$_3$)$_2$CHOCH(CH$_3$)$_2$	102.17	153.5	6.075	1.199	1.586	2.127	2.746	3.481	4.254	5.298
1,4-Dioxane	O·CH$_2$CH$_2$OCH$_2$CH$_2$	88.10	214.7	8.659	0.232	0.329	0.425	0.619	0.831	1.141	1.508
Dipropyl ether	CH$_3$CH$_2$CH$_2$OCH$_2$CH$_2$CH$_3$	102.17	195.8	6.260	0.425	0.619	0.831	1.102	1.431	1.876	2.320
Ethyl acetate	C$_2$H$_5$OOCCH$_3$	88.10	170.9	7.551	0.580	0.831	1.102	1.489	1.934	2.514	3.191
Ethyl acrylate	C$_2$H$_5$OOCCH:CH$_2$	100.11	211.8	7.750	0.213	0.290	0.425	0.599	0.831	1.122	1.470
Ethyl alcohol	C$_2$H$_5$OH	46.07	173.1	6.610	0.193	0.406	0.619	0.870	1.218	1.682	2.320
Freon 11	CC$_3$F	137.38	75.4	12.480	7.032	8.804	10.900	13.40	16.31	19.69	23.60

TABLE 12.3-3. (Continued)

Name	Formula	Molecular weight	Boiling point at 1 atmosphere (°F)	Liquid density at 60°F (pounds per gallon)	Vapor pressure (pounds per square inch absolute) at						
					40°F	50°F	60°F	70°F	80°F	90°F	100°F
n-Heptane	CH$_3$(CH$_2$)$_5$CH$_3$	100.20	209.2	5.727	0.290	0.406	0.541	0.735	0.967	1.238	1.586
n-Hexane	CH$_3$(CH$_2$)$_4$CH$_3$	86.17	155.7	5.527	1.102	1.450	1.876	2.436	3.055	3.906	4.892
Hydrogen cyanide	HCN	27.03	78.3	5.772	6.284	7.831	9.514	11.853	15.392	18.563	22.237
Isooctane	(CH$_3$)$_3$CCH$_2$CH(CH$_3$)$_2$	114.22	210.6	5.794	0.213	0.387	0.580	0.812	1.093	1.392	1.740
Isopentane	(CH$_3$)$_2$CHCH$_2$CH$_3$	72.15	82.1	5.199	5.878	7.889	10.005	12.530	15.334	18.370	21.657
Isoprene	(CH$_2$):C(CH$_3$)CH:CH$_2$	68.11	93.5	5.707	4.457	6.130	7.677	9.668	11.699	14.503	17.113
Isopropyl alcohol	(CH$_3$)$_2$·CHOH	60.09	180.1	6.573	0.213	0.329	0.483	0.677	0.928	1.296	1.779
Methacrylonitrile	CH$_2$:C(CH$_3$)CN	67.09	194.5	6.738	0.483	0.657	0.870	1.160	1.470	1.934	2.456
Methyl acetate	CH$_3$OOCCH$_3$	74.08	134.8	7.831	1.489	2.011	2.746	3.693	4.699	5.762	6.961
Methyl acrylate	CH$_3$OOCCH:CH$_2$	86.09	176.9	7.996	0.599	0.773	1.025	1.354	1.798	2.398	3.055
Methyl alcohol	CH$_3$OH	32.04	148.4	6.630	0.735	1.006	1.412	1.953	2.610	3.461	4.525
Methylcyclohexane	CH$_3$·C$_6$H$_{11}$	98.18	213.7	6.441	0.309	0.425	0.541	0.735	0.986	1.315	1.721
Methylcyclopentane	CH$_3$C$_5$H$_9$	84.16	161.3	6.274	0.909	1.160	1.644	2.224	2.862	3.616	4.544
Methylene chloride	CH$_2$Cl$_2$	84.94	104.2	11.122	3.094	4.254	5.434	6.787	8.702	10.329	13.342
Methyl ethyl ketone	CH$_3$COC$_2$H$_5$	72.10	175.3	6.747	0.715	0.928	1.199	1.489	2.069	2.668	3.345
Methyl methacrylate	CH$_3$OOCC(CH$_3$):CH$_2$	100.11	212.0	7.909	0.116	0.213	0.348	0.541	0.773	1.064	1.373
Methyl propyl ether	CH$_3$OC$_3$H$_7$	74.12	102.1	6.166	3.674	4.738	6.091	7.058	9.417	11.602	13.729
Nitromethane	CH$_3$NO$_2$	61.04	214.2	9.538	0.213	0.251	0.348	0.503	0.715	1.006	1.334
n-Pentane	CH$_3$(CH$_2$)$_3$CH$_3$	72.15	96.9	5.253	4.293	5.454	6.828	8.433	10.445	12.959	15.474
n-Propylamine	C$_3$H$_7$NH$_2$	59.11	119.7	6.030	2.456	3.191	4.157	5.250	6.536	8.044	9.572
1,1,1-Trichloroethane	CH$_3$CCl$_3$	133.42	165.2	11.216	0.909	1.218	1.586	2.030	2.610	3.307	4.199
Trichloroethylene	CHCl:CCl$_2$	131.40	188.6	12.272	0.503	0.677	0.889	1.180	1.508	2.030	2.610
Toluene	CH$_3$·C$_6$H$_5$	92.13	231.1	7.261	0.174	0.213	0.309	0.425	0.580	0.773	1.006
Vinyl acetate	CH$_2$:CHOOCCH$_3$	86.09	162.5	7.817	0.735	0.986	1.296	1.721	2.262	3.113	4.022
Vinylidene chloride	CH$_2$:CCl$_2$	96.5	89.1	10.383	4.990	6.344	7.930	9.806	11.799	15.280	23.210

*Reference 9.

TABLE 12.3-4 ASTM DISTILLATION SLOPE FOR SELECTED REFINED PETROLEUM
STOCKS[a]

Refined petroleum stock	Reid vapor pressure, RVP (psi)	ASTM-D86 distillation slope at 10 volume percent evaporated, ($°F/vol\%$)
Aviation gasoline	--	2.0
Naptha	2-8	2.5
Motor gasoline	--	3.0
Light naptha	9-14	3.5

[a]Reference 6.

TABLE 12.3-5. VAPOR PRESSURE EQUATION CONSTANTS FOR ORGANIC LIQUIDS[a]

Name	Vapor pressure equation constants		
	A	B	C
	(dimensioless)	(°C)	(°C)
Acetaldehyde	8.005	1600.017	291.809
Acetic acid	7.387	1533.313	222.309
Acetic anhydride	7.149	1444.718	199.817
Acetone	7.117	1210.595	229.664
Acetonitrile	7.119	1314.4	230
Acrylamide	11.2932	3939.877	273.16
Acrylic acid	5.652	648.629	154.683
Acrylonitrile	7.038	1232.53	222.47
Aniline	7.32	1731.515	206.049
Benzene	6.905	1211.033	220.79
Butanol (iso)	7.4743	1314.19	186.55
Butanol-(1)	7.4768	1362.39	178.77
Carbon disulfide	6.942	1169.11	241.59
Carbon tetrachloride	6.934	1242.43	230
Chlorobenzene	6.978	1431.05	217.55
Chloroform	6.493	929.44	196.03
Chloroprene	6.161	783.45	179.7
Cresol(-M)	7.508	1856.36	199.07
Cresol(-O)	6.911	1435.5	165.16
Cresol(-P)	7.035	1511.08	161.85
Cumene (isopropylbenzene)	6.963	1460.793	207.78
Cyclohexane	6.841	1201.53	222.65
Cyclohexanol	6.255	912.87	109.13
Cyclohexanone	7.8492	2137.192	273.16
Dichloroethane(1,2)	7.025	1272.3	222.9
Dichloroethylene(1,2)	6.965	1141.9	231.9
Diethyl (N,N) anilin	7.466	1993.57	218.5
Dimethyl formamide	6.928	1400.87	196.43
Dimethyl hydrazine (1,1)	7.408	1305.91	225.53
Dimethyl phthalate	4.522	700.31	51.42
Dinitrobenzene	4.337	229.2	-137
Dioxane(1,4)	7.431	1554.68	240.34
Epichlorohydrin	8.2294	2086.816	273.16
Ethanol	8.321	1718.21	237.52
Ethanolamine(mono-)	7.456	1577.67	173.37
Ethyl acrylate	7.9645	1897.011	273.16
Ethyl chloride	6.986	1030.01	238.61
Ethylacetate	7.101	1244.95	217.88
Ethylbenzene	6.975	1424.255	213.21

TABLE 12.3-5. (Continued)

| Name | Vapor pressure equation constants | | |
| | A | B | C |
	(dimensioless)	(°C)	(°C)
Ethylether	6.92	1064.07	228.8
Formic acid	7.581	1699.2	260.7
Furan	6.975	1060.87	227.74
Furfural	6.575	1198.7	162.8
Heptane(iso)	6.8994	1331.53	212.41
Hexane(-N)	6.876	1171.17	224.41
Hexanol(-1)	7.86	1761.26	196.66
Hydrocyanic acid	7.528	1329.5	260.4
Methanol	7.897	1474.08	229.13
Methyl acetate	7.065	1157.63	219.73
Methyl ethyl ketone	6.9742	1209.6	216
Methyl isobutyl ketone	6.672	1168.4	191.9
Methyl metharcrylate	8.409	2050.5	274.4
Methyl styrene (alpha)	6.923	1486.88	202.4
Methylene chloride	7.409	1325.9	252.6
Morpholine	7.7181	1745.8	235
Naphthalene	7.01	1733.71	201.86
Nitrobenzene	7.115	1746.6	201.8
Pentachloroethane	6.74	1378	197
Phenol	7.133	1516.79	174.95
Picoline(-2)	7.032	1415.73	211.63
Propanol (iso)	8.117	1580.92	219.61
Propylene glycol	8.2082	2085.9	203.5396
Propylene oxide	8.2768	1656.884	273.16
Pyridine	7.041	1373.8	214.98
Resorcinol	6.9243	1884.547	186.0596
Styrene	7.14	1574.51	224.09
Tetrachloroethane(1,1,1,2)	6.898	1365.88	209.74
Tetrachloroethane(1,1,2,2)	6.631	1228.1	179.9
Tetrachloroethylene	6.98	1386.92	217.53
Tetrahydrofuran	6.995	1202.29	226.25
Toluene	6.954	1344.8	219.48
Trichloro(1,1,2)trifluoroethane	6.88	1099.9	227.5
Trichloroethane(1,1,1)	8.643	2136.6	302.8
Trichloroethane(1,1,2)	6.951	1314.41	209.2
Trichloroethylene	6.518	1018.6	192.7
Trichlorofluoromethane	6.884	1043.004	236.88
Trichloropropane(1,2,3)	6.903	788.2	243.23
Vinyl acetate	7.21	1296.13	226.66

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TABLE 12.3-5. (Continued)

| Name | Vapor pressure equation constants | | |
	A	B	C
	(dimensioless)	(°C)	(°C)
Vinylidene chloride	6.972	1099.4	237.2
Xylene(-M)	7.009	1426.266	215.11
Xylene(-O)	6.998	1474.679	213.69

[a]Reference 10.

TABLE 12.3-6. METEOROLOGICAL DATA (T_AX, T_AN, I) FOR SELECTED U.S. LOCATIONS[a,b]

Location	Symbol	Units	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Annual average
									Monthly averages						
Birmingham, AL	T_AX	°F	52.7	57.3	65.2	75.2	81.6	87.9	90.3	89.7	84.6	74.8	63.7	55.9	73.2
	T_AN	°F	33.0	35.2	42.1	50.4	58.3	65.9	69.8	69.1	63.6	50.4	40.5	35.2	51.1
	I	Btu/ft² day	707	967	1296	1674	1857	1919	1810	1724	1455	1211	858	661	1345
Montgomery, AL	T_AX	°F	57.0	60.9	68.1	77.0	83.6	89.8	91.5	91.2	86.9	77.5	67.0	59.8	75.9
	T_AN	°F	36.4	38.8	45.5	53.3	61.1	68.4	71.8	71.1	66.4	53.1	43.0	37.9	53.9
	I	Btu/ft² day	752	1013	1341	1729	1897	1972	1841	1746	1468	1262	915	719	1388
Homer, AK	T_AX	°F	27.0	31.2	34.4	42.1	49.8	56.3	60.5	60.3	54.8	44.0	34.9	27.7	43.6
	T_AN	°F	14.4	17.4	19.3	28.1	34.6	41.2	45.1	45.2	39.7	30.6	22.8	15.8	29.5
	I	Btu/ft² day	122	334	759	1248	1583	1751	1598	1189	791	437	175	64	838
Phoenix, AZ	T_AX	°F	65.2	69.7	74.5	83.1	92.4	102.3	105.0	102.3	98.2	87.7	74.3	66.4	85.1
	T_AN	°F	39.4	42.5	46.7	53.0	61.5	70.6	79.5	77.5	70.9	59.1	46.9	40.2	57.3
	I	Btu/ft² day	1021	1374	1814	2355	2677	2739	2487	2293	2015	1577	1151	932	1869
Tucson, AZ	T_AX	°F	64.1	67.4	71.8	80.1	88.8	98.5	98.5	95.9	93.5	84.1	72.2	65.0	81.7
	T_AN	°F	38.1	40.0	43.8	49.7	57.5	67.4	73.8	72.0	67.3	56.7	45.2	39.0	54.2
	I	Btu/ft² day	1099	1432	1864	2363	2671	2730	2341	2183	1979	1602	1208	996	1872
Fort Smith, AR	T_AX	°F	48.4	53.8	62.5	73.7	81.0	88.5	93.6	92.9	85.7	75.9	61.9	52.1	72.5
	T_AN	°F	26.6	30.9	38.5	49.1	58.2	66.3	70.5	68.9	62.1	49.0	37.7	30.2	49.0
	I	Btu/ft² day	744	999	1312	1616	1912	2089	2065	1877	1502	1201	851	682	1404
Little Rock, AR	T_AX	°F	49.8	54.5	63.2	73.8	81.7	89.5	92.7	92.3	85.6	75.8	62.4	53.2	72.9
	T_AN	°F	29.9	33.6	41.2	50.9	59.2	67.5	71.4	69.6	63.0	50.4	40.0	33.2	50.8
	I	Btu/ft² day	731	1003	1313	1611	1929	2107	2032	1861	1518	1228	847	674	1404
Bakersfield, CA	T_AX	°F	57.4	63.7	68.6	75.1	83.9	92.2	98.8	96.4	90.8	81.0	67.4	57.6	77.7
	T_AN	°F	38.9	42.6	45.5	50.1	57.2	64.3	70.1	68.5	63.8	54.9	44.9	38.7	53.3
	I	Btu/ft² day	766	1102	1595	2095	2509	2749	2684	2421	1992	1458	942	677	1749
Long Beach, CA	T_AX	°F	66.0	67.3	68.0	70.9	73.4	77.4	83.0	83.8	82.5	78.4	72.7	67.4	74.2
	T_AN	°F	44.3	45.9	47.7	50.8	55.2	58.9	62.6	64.0	61.6	56.6	49.6	44.7	53.5
	I	Btu/ft² day	928	1215	1610	1938	2065	2140	2300	2100	1701	1326	1004	847	1598
Los Angeles AP, CA	T_AX	°F	64.6	65.5	65.1	66.7	69.1	72.0	75.3	76.5	76.4	74.0	70.3	66.1	70.1
	T_AN	°F	47.3	48.6	49.7	52.2	55.7	59.1	62.6	64.0	62.5	58.5	52.1	47.8	55.0
	I	Btu/ft² day	926	1214	1619	1951	2060	2119	2308	2080	1681	1317	1004	849	1594
Sacramento, CA	T_AX	°F	52.6	59.4	64.1	71.0	79.7	87.4	93.3	91.7	87.6	77.7	63.2	53.2	73.4
	T_AN	°F	37.9	41.2	42.4	45.3	50.1	55.1	57.9	57.6	55.8	50.0	42.8	37.9	47.8
	I	Btu/ft² day	597	939	1458	2004	2435	2684	2688	2368	1907	1315	782	538	1643
San Francisco AP, CA	T_AX	°F	55.5	59.0	60.6	63.0	66.3	69.6	71.0	71.8	73.4	70.0	62.7	56.3	64.9
	T_AN	°F	41.5	44.1	44.9	46.6	49.3	52.0	53.3	54.2	54.3	51.2	46.3	42.2	48.3
	I	Btu/ft² day	708	1009	1455	1920	2226	2377	2392	2117	1742	1226	821	642	1608

Table 12.3-6. (Continued)

Location	Symbol	Units	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Annual average
Santa Maria, CA	T_{AX}	°F	62.8	64.2	63.9	65.6	67.3	69.9	72.1	72.8	74.2	73.3	68.9	64.6	68.3
	T_{AN}	°F	38.8	40.3	40.9	42.7	46.2	49.6	52.4	53.2	51.8	47.6	42.1	38.3	45.3
	I	Btu/ft² day	854	1141	1582	1921	2141	2349	2341	2106	1730	1353	974	804	1608
Denver, CO	T_{AX}	°F	43.1	46.9	51.2	61.0	70.7	81.6	88.0	85.8	77.5	66.8	52.4	46.1	64.3
	T_{AN}	°F	15.9	20.2	24.7	33.7	43.6	52.4	58.7	57.0	47.7	36.9	25.1	18.9	36.2
	I	Btu/ft² day	840	1127	1530	1879	2135	2351	2273	2044	1727	1301	884	732	1568
Grand Junction, CO	T_{AX}	°F	35.7	44.5	54.1	65.2	76.2	87.9	94.0	90.3	81.9	68.7	51.0	38.7	65.7
	T_{AN}	°F	15.2	22.4	29.7	38.2	48.0	56.6	63.8	61.5	52.2	41.1	28.2	17.9	39.6
	I	Btu/ft² day	791	1119	1554	1986	2380	2599	2465	2182	1834	1345	918	731	1659
Wilmington, DE	T_{AX}	°F	39.2	41.8	50.9	63.0	72.7	81.2	85.6	84.1	77.8	66.7	54.8	43.6	63.5
	T_{AN}	°F	23.2	24.6	32.6	41.8	51.7	61.2	66.3	65.4	58.0	45.9	36.4	27.3	44.5
	I	Btu/ft² day	571	827	1149	1480	1710	1883	1823	1615	1318	984	645	489	1208
Atlanta, GA	T_{AX}	°F	51.2	55.3	63.2	73.2	79.8	85.6	87.9	87.6	82.3	72.9	62.6	54.1	71.3
	T_{AN}	°F	32.6	34.5	41.7	50.4	58.7	65.9	69.2	68.7	63.6	51.4	41.3	34.8	51.1
	I	Btu/ft² day	718	969	1304	1686	1854	1914	1812	1709	1422	1200	883	674	1345
Savannah, GA	T_{AX}	°F	60.3	63.1	69.9	77.8	84.2	88.6	90.8	90.1	85.6	77.8	69.5	62.5	76.7
	T_{AN}	°F	37.9	40.0	46.8	54.1	62.3	68.5	71.5	71.4	67.6	55.9	45.5	39.4	55.1
	I	Btu/ft² day	795	1044	1399	1761	1852	1844	1784	1621	1364	1217	941	754	1365
Honolulu, HI	T_{AX}	°F	79.9	80.4	81.4	82.7	84.8	86.2	87.1	88.3	88.2	86.7	83.9	81.4	84.2
	T_{AN}	°F	65.3	65.3	67.3	68.7	70.2	71.9	73.1	73.6	72.9	72.2	69.2	66.5	69.7
	I	Btu/ft² day	1180	1396	1622	1796	1949	2004	2002	1967	1810	1540	1266	1133	1639
Chicago, IL	T_{AX}	°F	29.2	33.9	44.3	58.8	70.0	79.4	83.3	82.1	75.5	64.1	48.2	35.0	58.7
	T_{AN}	°F	13.6	18.1	27.6	38.8	48.1	57.7	62.7	61.7	53.9	42.9	31.4	20.3	39.7
	I	Btu/ft² day	507	760	1107	1459	1789	2007	1944	1719	1354	969	566	402	1215
Springfield, IL	T_{AX}	°F	32.8	38.0	48.9	64.0	74.6	84.1	87.1	84.7	79.3	67.5	51.2	38.4	62.6
	T_{AN}	°F	16.3	20.9	30.3	42.6	52.5	62.0	65.9	63.7	55.8	44.4	32.9	23.0	42.5
	I	Btu/ft² day	585	861	1143	1515	1866	2097	2058	1806	1454	1068	677	490	1302
Indianapolis, IN	T_{AX}	°F	34.2	38.5	49.3	63.1	73.4	82.3	85.2	83.7	77.9	66.1	50.8	39.2	62.0
	T_{AN}	°F	17.8	21.1	30.7	41.7	51.5	60.9	64.9	62.7	55.3	43.4	32.8	23.7	42.2
	I	Btu/ft² day	496	747	1037	1398	1638	1868	1806	1644	1324	977	579	417	1165
Wichita, KS	T_{AX}	°F	39.8	46.1	55.8	68.1	77.1	87.4	92.9	91.5	82.0	71.2	55.1	44.6	67.6
	T_{AN}	°F	19.4	24.1	32.4	44.5	54.6	64.7	69.8	67.9	59.2	46.9	33.5	24.2	45.1
	I	Btu/ft² day	784	1058	1406	1783	2036	2264	2239	2032	1616	1250	871	690	1502

Storage of Organic Liquids

Table 12.3-6. (Continued)

Location	Symbol	Units	Monthly averages												Annual average
			Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	
Louisville, KY	T_{AX}	°F	40.8	45.0	54.9	67.5	76.2	84.0	87.6	86.7	80.6	69.2	55.5	45.4	66.1
	T_{AN}	°F	24.1	26.8	35.2	45.6	54.6	63.3	67.5	66.1	59.1	46.2	36.6	28.9	46.2
	I	Btu/ft² day	546	789	1102	1467	1720	1904	1838	1680	1361	1042	653	488	1216
Baton Rouge, LA	T_{AX}	°F	61.1	64.5	71.6	79.2	85.2	90.6	91.4	90.8	87.4	80.1	70.1	63.8	78.0
	T_{AN}	°F	40.5	42.7	49.4	57.5	64.3	70.0	72.8	72.0	68.3	56.3	47.2	42.3	57.0
	I	Btu/ft² day	785	1054	1379	1681	1871	1926	1746	1677	1464	1301	920	737	1379
Lake Charles, LA	T_{AX}	°F	60.8	64.0	70.5	77.8	84.1	89.4	91.0	90.8	87.5	80.8	70.5	64.0	77.6
	T_{AN}	°F	42.2	44.5	50.8	58.9	65.6	71.4	73.5	72.8	68.9	57.7	48.9	43.8	58.3
	I	Btu/ft² day	728	1010	1313	1570	1849	1970	1788	1657	1485	1381	917	706	1365
New Orleans, LA	T_{AX}	°F	61.8	64.6	71.2	78.6	84.5	89.5	90.7	90.2	86.8	79.4	70.1	64.4	77.7
	T_{AN}	°F	43.0	44.8	51.6	58.8	65.3	70.9	73.5	73.1	70.1	59.0	49.9	44.8	58.7
	I	Btu/ft² day	835	1112	1415	1780	1968	2004	1814	1717	1514	1335	973	779	1437
Detroit, MI	T_{AX}	°F	30.6	33.5	43.4	57.7	69.4	79.0	83.1	81.5	74.4	62.5	47.6	35.4	58.2
	T_{AN}	°F	16.1	18.0	26.5	36.9	46.7	56.3	60.7	59.4	52.2	41.2	31.4	21.6	38.9
	I	Btu/ft² day	417	680	1000	1399	1716	1866	1835	1576	1253	876	478	344	1120
Grand Rapids, MI	T_{AX}	°F	29.0	31.7	41.6	56.9	69.4	78.9	83.0	81.1	73.4	61.4	46.0	33.8	57.2
	T_{AN}	°F	14.9	15.6	24.5	35.6	45.5	55.3	59.8	58.1	50.8	40.4	30.9	20.7	37.7
	I	Btu/ft² day	370	648	1014	1412	1755	1957	1914	1676	1262	858	446	311	1135
Minneapolis-St. Paul, MN	T_{AX}	°F	19.9	26.4	37.5	56.0	69.4	78.5	83.4	80.9	71.0	59.7	41.1	26.7	54.2
	T_{AN}	°F	2.4	8.5	20.8	36.0	47.6	57.7	62.7	60.3	50.2	39.4	25.3	11.7	35.2
	I	Btu/ft² day	464	764	1104	1442	1737	1928	1970	1687	1255	860	480	353	1170
Jackson, MS	T_{AX}	°F	56.5	60.9	68.4	77.3	84.1	90.5	92.5	92.1	87.6	78.6	67.5	60.0	76.3
	T_{AN}	°F	34.9	37.2	44.2	52.9	60.8	67.9	71.3	70.2	65.1	51.4	42.3	37.1	52.9
	I	Btu/ft² day	754	1026	1369	1708	1941	2024	1909	1781	1509	1271	902	709	1409
Billings, MT	T_{AX}	°F	29.9	37.9	44.0	55.9	66.4	76.3	86.6	84.3	72.3	61.0	44.4	36.0	57.9
	T_{AN}	°F	11.8	18.8	23.6	33.2	43.3	51.6	58.0	56.2	46.5	37.5	25.5	18.2	35.4
	I	Btu/ft² day	486	763	1190	1526	1913	2174	2384	2022	1470	987	561	421	1325
Las Vegas, NV	T_{AX}	°F	56.0	62.4	68.3	77.2	87.4	98.6	104.5	101.9	94.7	81.5	66.0	57.1	79.6
	T_{AN}	°F	33.0	37.7	42.3	49.8	59.0	68.6	75.9	73.9	65.6	53.5	41.2	33.6	52.8
	I	Btu/ft² day	978	1340	1824	2319	2646	2778	2588	2355	2037	1540	1086	881	1864
Newark, NJ	T_{AX}	°F	38.2	40.3	49.1	61.3	71.6	80.6	85.6	84.0	76.9	66.0	54.0	42.3	62.5
	T_{AN}	°F	24.2	25.3	33.3	42.9	53.0	62.4	67.9	67.0	59.4	48.3	39.0	28.6	45.9
	I	Btu/ft² day	552	793	1109	1449	1687	1795	1760	1565	1273	951	596	454	1165

EMISSION FACTORS

Table 12.3-6. (Continued)

Location	Symbol	Units	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Annual average
Roswell, NM	T_{AX}	°F	55.4	60.4	67.7	76.9	85.0	93.1	93.7	91.3	84.9	75.8	63.1	56.7	75.3
	T_{AN}	°F	27.4	31.4	37.9	46.8	55.6	64.8	69.0	67.0	59.6	47.5	35.0	28.2	47.5
	I	Btu/ft² day	1047	1373	1807	2218	2459	2610	2441	2242	1913	1527	1131	952	1810
Buffalo, NY	T_{AX}	°F	30.0	31.4	40.4	54.4	65.9	75.6	80.2	78.2	71.4	60.2	47.0	35.0	55.8
	T_{AN}	°F	17.0	17.5	25.6	36.3	46.3	56.4	61.2	59.6	52.7	42.7	33.6	22.5	39.3
	I	Btu/ft² day	349	546	889	1315	1597	1804	1776	1513	1152	784	403	283	1034
New York, NY (LaGuardia Airport)	T_{AX}	°F	37.4	39.2	47.3	59.6	69.7	78.7	83.9	82.3	75.2	64.5	52.9	41.5	61.0
	T_{AN}	°F	26.1	27.3	34.6	44.2	53.7	63.2	68.9	68.2	61.2	50.5	41.2	30.8	47.5
	I	Btu/ft² day	548	795	1118	1457	1690	1802	1784	1583	1280	951	593	457	1171
Cleveland, OH	T_{AX}	°F	32.5	34.8	44.8	57.9	68.5	78.0	81.7	80.3	74.2	62.7	49.3	37.5	58.5
	T_{AN}	°F	18.5	19.9	28.4	38.3	47.9	57.2	61.4	60.5	54.0	43.6	34.3	24.6	40.7
	I	Btu/ft² day	388	601	922	1350	1681	1843	1828	1583	1240	867	466	318	1091
Columbus, OH	T_{AX}	°F	34.7	38.1	49.3	62.3	72.6	81.3	84.4	83.0	76.9	65.0	50.7	39.4	61.5
	T_{AN}	°F	19.4	21.5	30.6	40.5	50.2	59.0	63.2	61.7	54.6	42.8	33.5	24.7	41.8
	I	Btu/ft² day	459	677	980	1353	1647	1813	1755	1641	1282	945	538	387	1123
Toledo, OH	T_{AX}	°F	30.7	34.0	44.6	59.1	70.5	79.9	83.4	81.8	75.1	63.3	47.9	35.5	58.8
	T_{AN}	°F	15.5	17.5	26.1	36.5	46.6	56.0	60.2	58.4	51.2	40.1	30.6	20.6	38.3
	I	Btu/ft² day	435	680	997	1384	1717	1878	1849	1616	1276	911	498	355	1133
Oklahoma City, OK	T_{AX}	°F	46.6	52.2	61.0	71.7	79.0	87.6	93.5	92.8	84.7	74.3	59.9	50.7	71.2
	T_{AN}	°F	25.2	29.4	37.1	48.6	57.7	66.3	70.6	69.4	61.9	50.2	37.6	29.1	48.6
	I	Btu/ft² day	801	1055	1400	1725	1918	2144	2128	1950	1554	1233	901	725	1461
Tulsa, OK	T_{AX}	°F	45.6	51.9	60.8	72.4	79.7	87.9	93.9	93.0	85.0	74.9	60.2	50.3	71.3
	T_{AN}	°F	24.8	29.5	37.7	49.5	58.5	67.5	72.4	70.3	62.5	50.3	38.1	29.3	49.2
	I	Btu/ft² day	732	978	1306	1603	1822	2021	2031	1865	1473	1164	827	659	1373
Astoria, OR	T_{AX}	°F	46.8	50.6	51.9	55.5	60.2	63.9	67.9	68.6	67.8	61.4	53.5	48.8	58.1
	T_{AN}	°F	35.4	37.1	36.9	39.7	44.1	49.2	52.2	52.6	49.2	44.3	39.7	37.3	43.1
	I	Btu/ft² day	315	545	866	1253	1608	1626	1746	1499	1183	713	387	261	1000
Portland, OR	T_{AX}	°F	44.3	50.4	54.5	60.2	66.9	72.7	79.5	78.6	74.2	63.9	52.3	46.4	62.0
	T_{AN}	°F	33.5	36.0	37.4	40.6	46.4	52.2	55.8	55.8	51.1	44.6	38.6	35.4	44.0
	I	Btu/ft² day	310	554	895	1308	1663	1773	2037	1674	1217	724	388	260	1067
Philadelphia, PA	T_{AX}	°F	38.6	41.1	50.5	63.2	73.0	81.7	86.1	84.6	77.8	66.5	54.5	43.0	63.4
	T_{AN}	°F	23.8	25.0	33.1	42.6	52.5	61.5	66.8	66.0	58.6	46.5	37.1	28.0	45.1
	I	Btu/ft² day	555	795	1108	1434	1660	1811	1758	1575	1281	959	619	470	1169

Table 12.3-6. (Continued)

| Location | Property | | | Monthly averages | | | | | | | | | | | | Annual average |
	Symbol	Units	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	
Pittsburgh, PA	T_{AX}	°F	34.1	36.8	47.6	60.7	70.8	79.1	82.7	81.1	74.8	62.9	49.8	38.4	59.9
	T_{AN}	°F	19.2	20.7	29.4	39.4	48.5	57.1	61.3	60.1	53.3	42.1	33.3	24.3	40.7
	I	Btu/ft² day	424	625	943	1317	1602	1762	1689	1510	1209	895	505	347	1069
Providence, RI	T_{AX}	°F	36.4	37.7	45.5	57.5	67.6	76.6	81.7	80.3	73.1	63.2	51.9	40.5	59.3
	T_{AN}	°F	20.0	20.9	29.2	38.3	47.6	57.0	63.3	61.9	53.8	43.1	34.8	24.1	41.2
	I	Btu/ft² day	506	739	1032	1374	1655	1776	1695	1499	1209	907	538	419	1112
Columbia, SC	T_{AX}	°F	56.2	59.5	67.1	77.0	83.8	89.2	91.9	91.0	85.5	76.5	67.1	58.8	75.3
	T_{AN}	°F	33.2	34.6	41.9	50.5	59.1	66.1	70.1	69.4	63.9	50.3	40.6	34.7	51.2
	I	Btu/ft² day	762	1021	1355	1747	1895	1947	1842	1703	1439	1211	921	722	1380
Sioux Falls, SD	T_{AX}	°F	22.9	29.3	40.1	58.1	70.5	80.3	86.2	83.9	73.5	62.1	43.7	29.3	56.7
	T_{AN}	°F	1.9	8.9	20.6	34.6	45.7	56.3	61.8	59.7	48.5	36.7	22.3	10.1	33.9
	I	Btu/ft² day	533	802	1152	1543	1894	2100	2150	1845	1410	1005	608	441	1290
Memphis, TN	T_{AX}	°F	48.3	53.0	61.4	72.9	81.0	88.4	91.5	90.3	84.3	74.5	61.4	52.3	71.6
	T_{AN}	°F	30.9	34.1	41.9	52.2	60.9	68.9	72.6	70.8	64.1	51.3	41.1	34.3	51.9
	I	Btu/ft² day	683	945	1278	1639	1885	2045	1972	1824	1471	1205	817	629	1366
Amarillo, TX	T_{AX}	°F	49.1	53.1	60.8	71.0	79.1	88.2	91.4	89.6	82.4	72.7	58.7	51.8	70.7
	T_{AN}	°F	21.7	26.1	32.0	42.0	51.9	61.5	66.2	64.5	56.9	45.5	32.1	24.8	43.8
	I	Btu/ft² day	960	1244	1631	2019	2212	2393	2281	2103	1761	1404	1033	872	1659
Corpus Christi, TX	T_{AX}	°F	66.5	69.9	76.1	82.1	86.7	91.2	94.2	94.1	90.1	83.9	75.1	69.3	81.6
	T_{AN}	°F	46.1	48.7	55.7	63.9	69.5	74.1	75.6	75.8	72.8	64.1	54.9	48.8	62.5
	I	Btu/ft² day	898	1147	1430	1642	1866	2094	2186	1991	1687	1416	1043	845	1521
Dallas, TX	T_{AX}	°F	54.0	59.1	67.2	76.8	84.4	93.2	97.8	97.3	89.7	79.5	66.2	58.1	76.9
	T_{AN}	°F	33.9	37.8	44.9	55.0	62.9	70.8	74.7	73.7	67.5	56.3	44.9	37.4	55.0
	I	Btu/ft² day	822	1071	1422	1627	1889	2135	2122	1950	1587	1276	936	780	1468
Houston, TX	T_{AX}	°F	61.9	65.7	72.1	79.0	85.1	90.9	93.6	93.1	88.7	81.9	71.6	65.2	79.1
	T_{AN}	°F	40.8	43.2	49.8	58.3	64.7	70.2	72.5	72.1	68.1	57.5	48.6	42.7	57.4
	I	Btu/ft² day	772	1034	1297	1522	1775	1898	1828	1686	1471	1276	924	730	1351
Midland-Odessa, TX	T_{AX}	°F	57.6	62.1	69.8	78.8	86.0	93.0	94.2	93.1	86.4	77.7	65.5	59.7	77.0
	T_{AN}	°F	29.7	33.3	40.2	49.4	58.2	66.6	69.2	68.0	61.9	51.1	39.0	32.2	49.9
	I	Btu/ft² day	1081	1383	1839	2192	2430	2562	2389	2210	1844	1522	1176	1000	1802
Salt Lake City, UT	T_{AX}	°F	37.4	43.7	51.5	61.1	72.4	83.3	93.2	90.0	80.0	66.7	50.2	38.9	64.0
	T_{AN}	°F	19.7	24.4	29.9	37.2	45.2	53.3	61.8	59.7	50.0	39.3	29.2	21.6	39.3
	I	Btu/ft² day	639	989	1454	1894	2362	2561	2590	2254	1843	1293	788	570	1603

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Table 12.3-6. (Continued)

Location	Property Symbol	Units	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Annual average
Richmond, VA	T_{AX}	°F	46.7	49.6	58.5	70.6	77.9	84.8	88.4	87.1	81.0	70.5	60.5	50.2	68.8
	T_{AN}	°F	26.5	28.1	35.8	45.1	54.2	62.2	67.2	66.4	59.3	46.7	37.3	29.6	46.5
	I	Btu/ft² day	632	877	1210	1566	1762	1872	1774	1601	1348	1033	733	567	1248
Seattle, WA (Sea-Tac Airport)	T_{AX}	°F	43.9	48.8	51.1	56.8	64.0	69.2	75.2	73.9	68.7	59.5	50.3	45.6	58.9
	T_{AN}	°F	34.3	36.8	37.2	40.5	46.0	51.1	54.3	54.3	51.2	45.3	39.3	36.3	43.9
	I	Btu/ft² day	262	495	849	1294	1714	1802	2248	1616	1148	656	337	211	1053
Charleston, WV	T_{AX}	°F	41.8	45.4	55.4	67.3	76.0	82.5	85.2	84.2	78.7	67.7	55.6	45.9	65.5
	T_{AN}	°F	23.9	25.8	34.1	43.3	51.8	59.4	63.8	63.1	56.4	44.0	35.0	27.8	44.0
	I	Btu/ft² day	498	707	1010	1356	1639	1776	1683	1514	1272	972	613	440	1123
Huntington, WV	T_{AX}	°F	41.1	45.0	55.2	67.2	75.7	82.6	85.6	84.4	78.7	67.6	55.2	45.2	65.3
	T_{AN}	°F	24.5	26.6	35.0	44.4	52.8	60.7	65.1	64.0	57.2	44.9	35.9	28.5	45.0
	I	Btu/ft² day	526	757	1067	1448	1710	1844	1769	1580	1306	1004	638	467	1176
Cheyenne, WY	T_{AX}	°F	37.3	40.7	43.6	54.0	64.6	75.4	83.1	80.8	72.1	61.0	46.5	40.4	58.3
	T_{AN}	°F	14.8	17.9	20.6	29.6	39.7	48.5	54.6	52.8	43.7	34.0	23.1	18.2	33.1
	I	Btu/ft² day	766	1068	1433	1771	1995	2258	2230	1966	1667	1242	823	671	1491

[a]Reference 11.
[b]Reference 12.

TABLE 12.3-7. PAINT SOLAR ABSORPTANCE FOR FIXED ROOF TANKS[a,b,c]

Paint color	Paint shade or type	Paint factors (α)	
		Paint condition	
		Good	Poor
Aluminum	Specular	0.39	0.49
Aluminum	Diffuse	0.60	0.68
Gray	Light	0.54	0.63
Gray	Medium	0.68	0.74
Red	Primer	0.89	0.91
White	--	0.17	0.34

[a]Reference 6.

[b]If specific information is not available, a white shell and roof, with the paint in good condition, can be assumed to represent the most common or typical tank paint in use.

[c]If the tank roof and shell are painted a different color, α is determined from
$\alpha = (\alpha_R + \alpha_s)/2$; where α_R is the tank roof paint solar absorptance and α_s is the tank shell paint solar absorptance.

12.3.2 Total Losses From External Floating Roof Tanks[3,4,11]

Total external floating roof tank emissions are the sum of rim seal, withdrawal, and roof fitting losses. The equations presented in this subsection apply only to external floating roof tanks. The equations are not intended to be used in the following applications:

1. To estimate losses from unstable or boiling stocks or from mixtures of hydrocarbons or petrochemicals for which the vapor pressure is not known or cannot readily be predicted; or

2. To estimate losses from tanks in which the materials used in the rim seal and/or roof fitting are either deteriorated or significantly permeated by the stored liquid.

Total losses from external floating roof tanks may be written as:

$$L_T = L_R + L_{WD} + L_F \qquad (2\text{-}1)$$

where:

L_T = total loss, lb/yr

L_R = rim seal loss, lb/yr; see Equation 2-2

L_{WD} = withdrawal loss, lb/yr; see Equation 2-4

L_F = roof fitting loss, lb/yr; see Equation 2-5

Rim Seal Loss - Rim seal loss from floating roof tanks can be estimated using the following equation:

$$L_R = K_R v^n P^* D M_V K_C \qquad (2\text{-}2)$$

where:

L_R = rim seal loss, lb/yr

K_R = seal factor, lb-mole/(mph)^{n}ft•yr; see Table 12.3-8 or Note 3

v = average wind speed at tank site, mph; see Note 1 and Note 3

n = seal-related wind speed exponent, dimensionless; see Table 12.3-8 or Note 3

P^* = vapor pressure function, dimensionless; see Note 2

$$P^* = \frac{P_{VA}/P_A}{[1 + (1 - [P_{VA}/P_A])^{0.5}]^2} \qquad (2\text{-}3)$$

where:

P_{VA} = vapor pressure at daily average liquid surface temperature, psia; See Notes 1 and 2 to Equation 1-9

P_A = atmospheric pressure, 14.7 psia

D = tank diameter, ft

M_V = average vapor molecular weight, lb/lb-mole; see Note 1 to Equation 1-9,

K_C = product factor, K_C = 0.4 for crude oils; K_C = 1 for all other organic liquids.

Notes:

1. If the wind speed at the tank site is not available, use wind speed data from the nearest local weather station or values from Table 12.3-9.

2. P* can be calculated or read directly from Figure 12.3-7.

3. The rim seal loss factor, $F_R = K_R v^n$, can also be read directly from Figures 12.3-8 through 12.3-11. Figures 12.3-8 through 12.3-11 present F_R for both average and tight fitting seals. However, it is recommended that only the values for average fitting seals be used in estimating rim seal losses because of the difficulty in ensuring the seals are tight fitting at all liquid heights in the tank.

Withdrawal Loss - The withdrawal loss from floating roof storage tanks can be estimated using Equation 2-4.

$$L_{WD} = \frac{(0.943)QCW_L}{D} \qquad (2\text{-}4)$$

where:

L_{WD} = withdrawal loss, lb/yr

Q = annual throughput, bbl/yr, (tank capacity [bbl] times annual turnover rate)

C = shell clingage factor, bbl/1,000 ft^2; see Table 12.3-10

W_L = average organic liquid density, lb/gal; see Note

D = tank diameter, ft

0.943 = constant, $1,000 \text{ ft}^3 \times \text{gal/bbl}^2$

Note: A listing of the average organic liquid density for select petrochemicals is provided in Tables 12.3-2 and 12.3-3. If W_L is not known for gasoline, an average value of 6.1 lb/gal can be assumed.

Roof Fitting Loss - The roof fitting loss from external floating roof tanks can be estimated by the following equation:

$$L_F = F_F P^* M_V K_C \qquad (2\text{-}5)$$

where:

L_F = the roof fitting loss, lb/yr

F_F = total roof fitting loss factor, lb-mole/yr; see Figures 12.3-12 and 12.3-13

$$= [(N_{F1} K_{F1}) + (N_{F2} K_{F2}) + ... + (N_{Fn} K_{Fn})] \qquad (2\text{-}6)$$

where:

N_{F_i} = number of roof fittings of a particular type ($i = 0,1,2,...,n_f$), dimensionless

K_{F_i} = roof fitting loss factor for a particular type fitting ($i = 0,1,2,...,n_f$), lb-mole/yr; see Equation 2-7

n_f = total number of different types of fittings, dimensionless

P^*, M_V, K_C are as defined for Equation 2-2.

The value of F_F may be calculated by using actual tank-specific data for the number of each fitting type (N_F) and then multiplying by the fitting loss factor for each fitting (K_F).

The roof fitting loss factor, K_{F_i} for a particular type of fitting, can be estimated by the following equation:

$$K_{F_i} = K_{F_{ai}} + K_{F_{bi}} v^{m_i} \qquad (2\text{-}7)$$

where:

K_i = loss factor for a particular type of roof fitting, lb-moles/yr

$K_{F_{ai}}$ = loss factor for a particular type of roof fitting, lb-moles/yr

$K_{F_{bi}}$ = loss factor for a particular type of roof fitting, lb-mole/(mph)$^m \bullet$yr

m_i = loss factor for a particular type of roof fitting, dimensionless

i = 1, 2, ..., n, dimensionless

v = average wind speed, mph

Loss factors K_{F_a}, K_{F_b}, and m are provided in Table 12.3-11 for the most common roof fittings used on external floating roof tanks. These factors apply only to typical roof fitting conditions and when the average wind speed is between 2 and 15 miles per hour. Typical number of fittings are presented in Tables 12.3-11, 12.3-12, and 12.3-13. Where tank-specific data for the number and kind of deck fittings are unavailable, F_F can be approximated according to tank diameter. Figures 12.3-12 and 12.3-13 present F_F plotted against tank diameter for pontoon and double-deck external floating roofs, respectively.

$$P^* = \frac{P/P_a}{\{1 + [1 - (P/P_a)]^{0.5}\}^2}$$
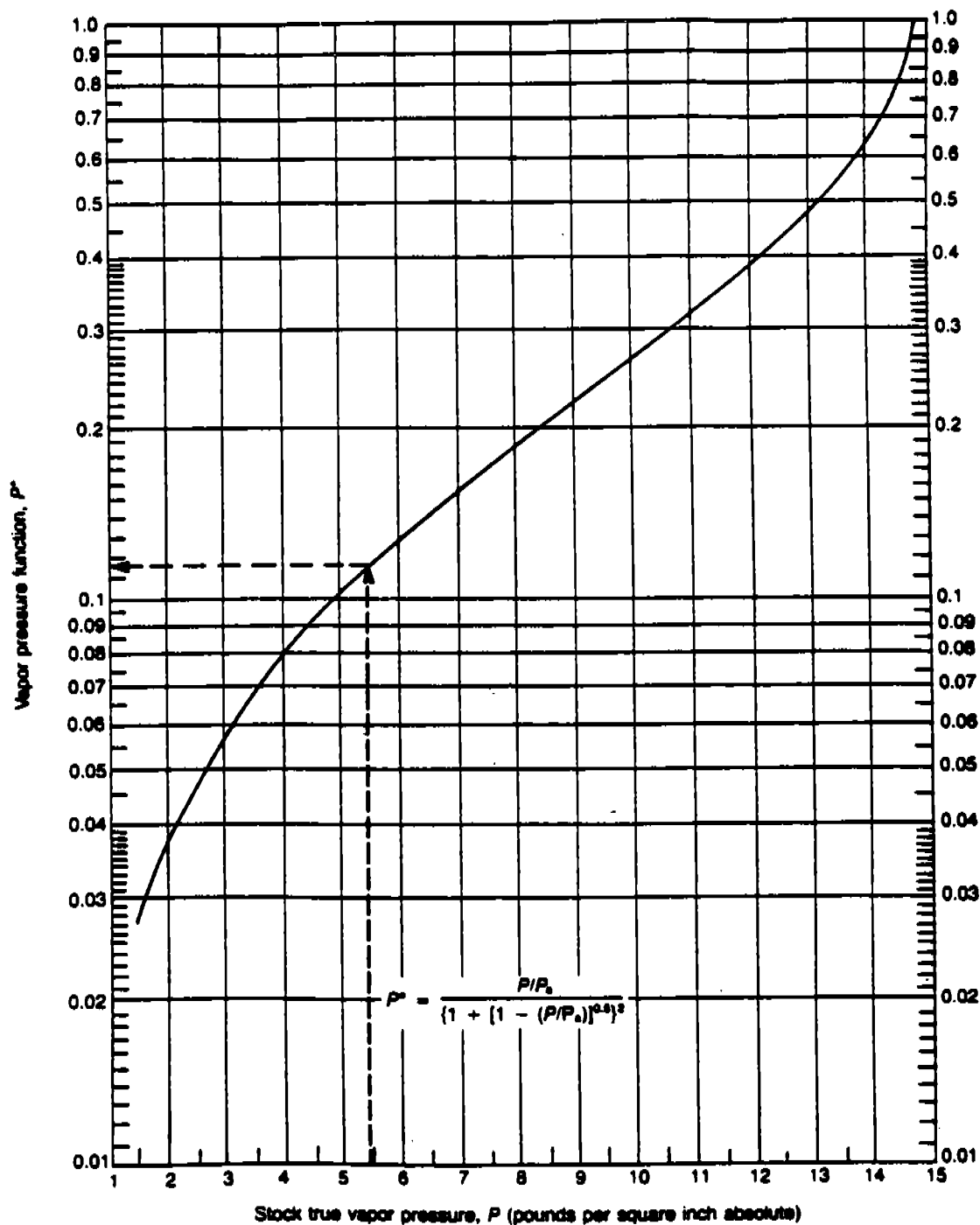
Notes:

1. Broken line illustrates sample problem for $P = 5.4$ pounds per square inch absolute.
2. Curve is for atmospheric pressure, P_a, equal to 14.7 pounds per square inch absolute.

Figure 12.3-7. Vapor pressure function.[4]
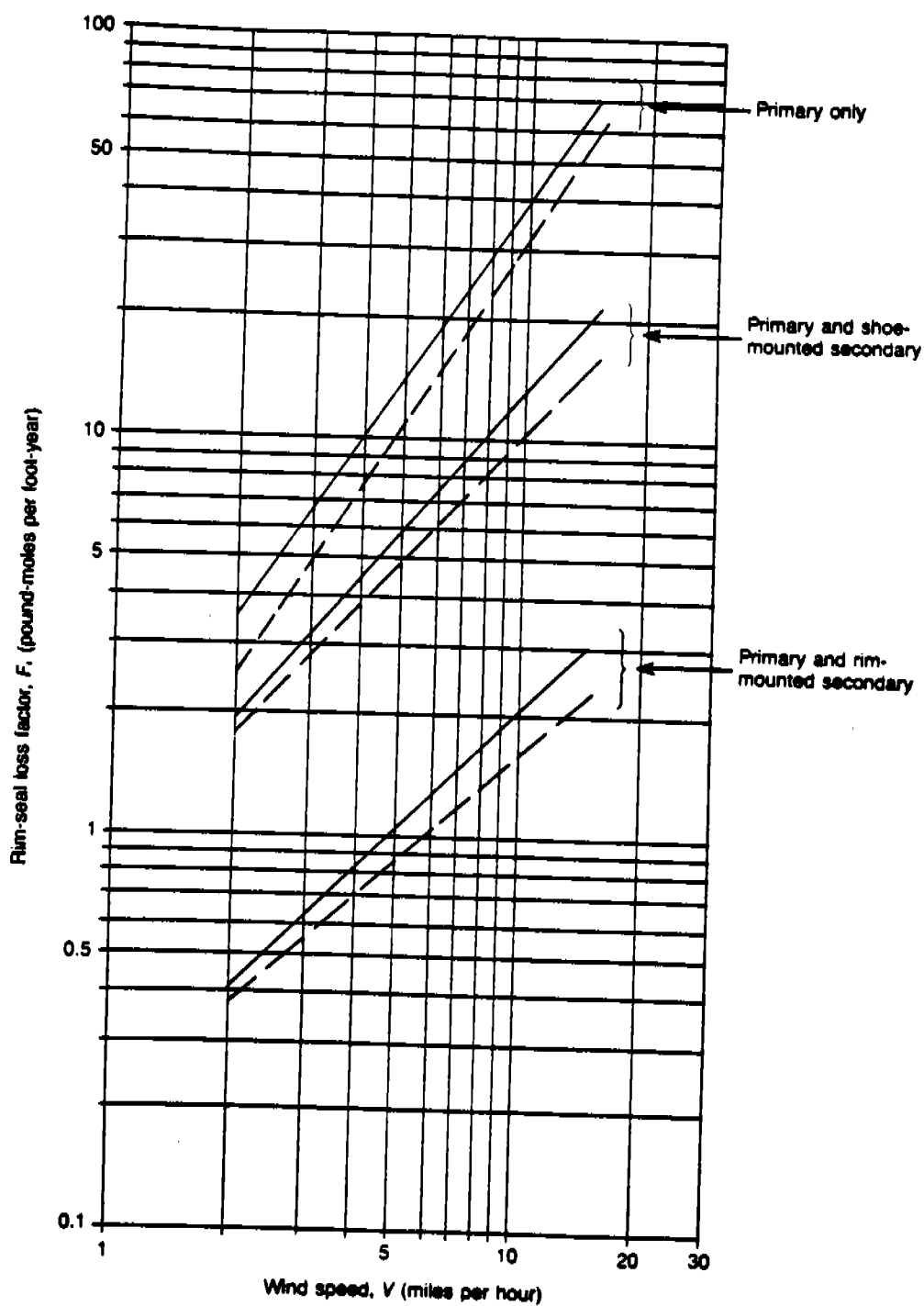
Note: Solid line indicates average-fitting seal; broken line indicates tight-fitting seal; $F_r = K_r V^n$.

Figure 12.3-8. Rim-seal loss factor for a welded tank with a mechanical-shoe primary seal.[3]
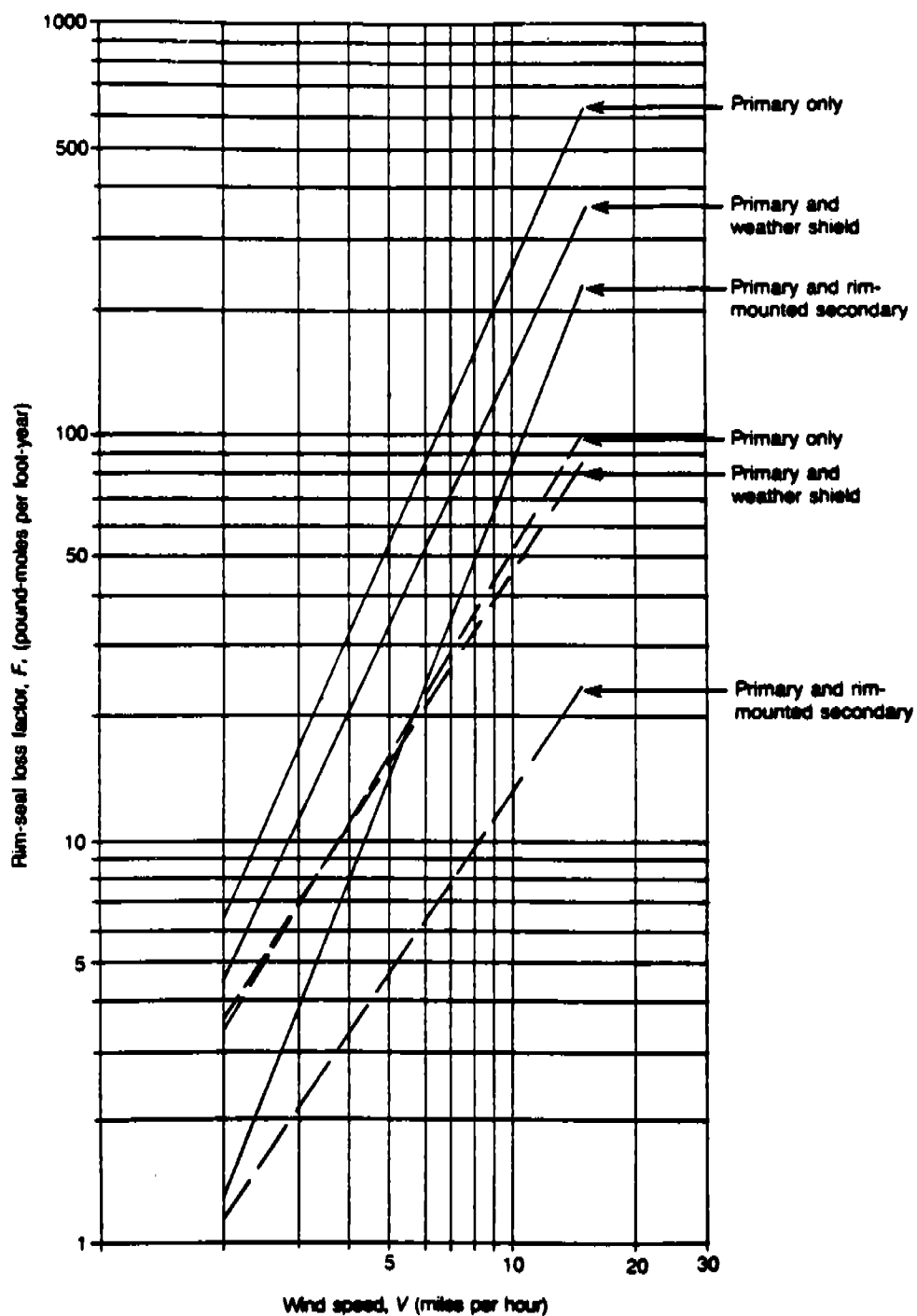
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Note: Solid line indicates average-fitting seal; broken line indicates tight-fitting seal; $F_r = K_r V^n$.

Figure 12.3-9. Rim-seal loss factor for a welded tank with a vapor-mounted, resilient-filled primary seal.[3]
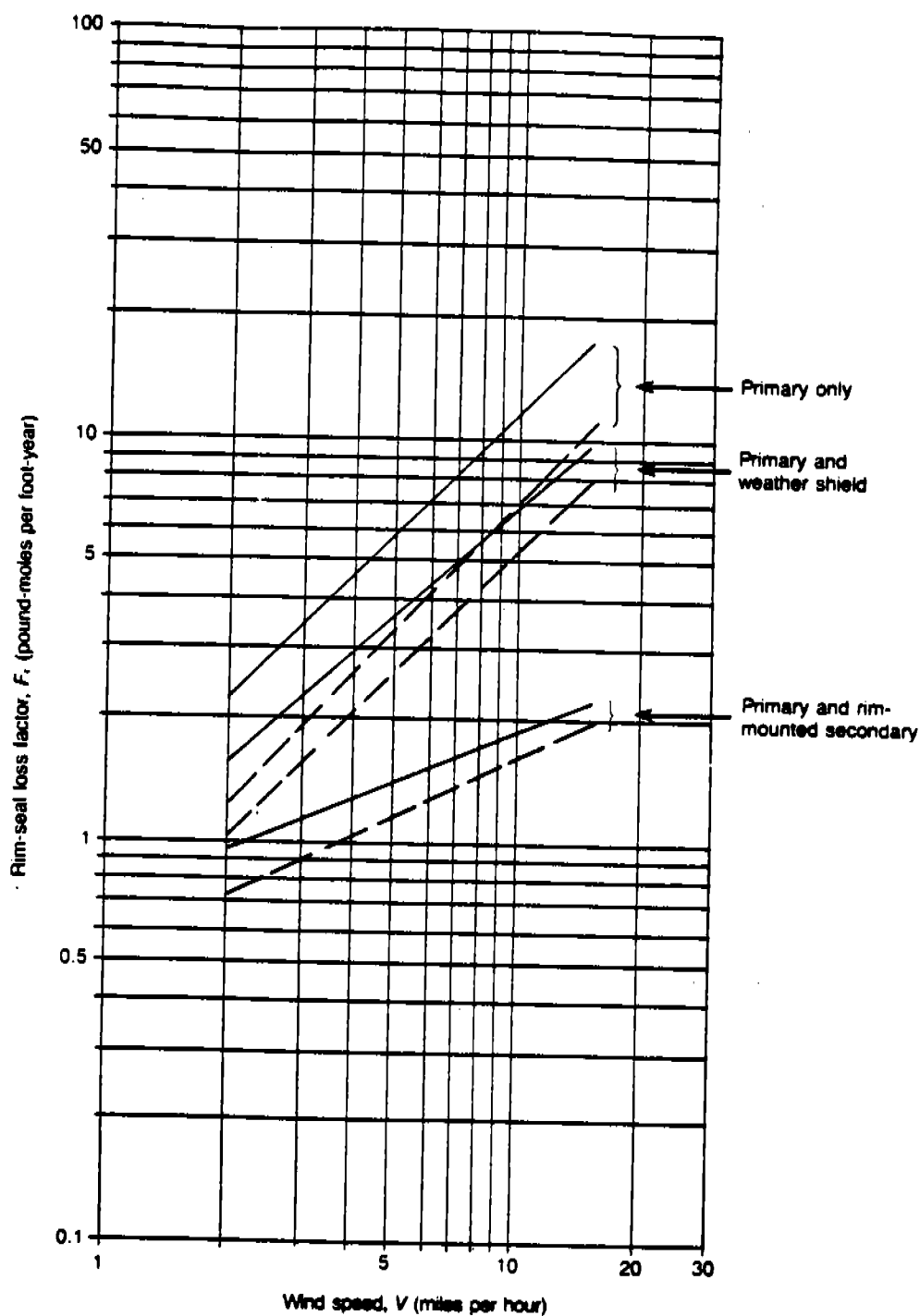
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Note: Solid line indicates average-fitting seal; broken line indicates tight-fitting seal; $F_r = K_r V^n$.

Figure 12.3-10. Rim-seal loss factor for a welded tank with
a liquid-mounted, resilient-filled primary seal.[3]

Note: Solid line indicates average-fitting seal; $F_t = K_t V^n$.
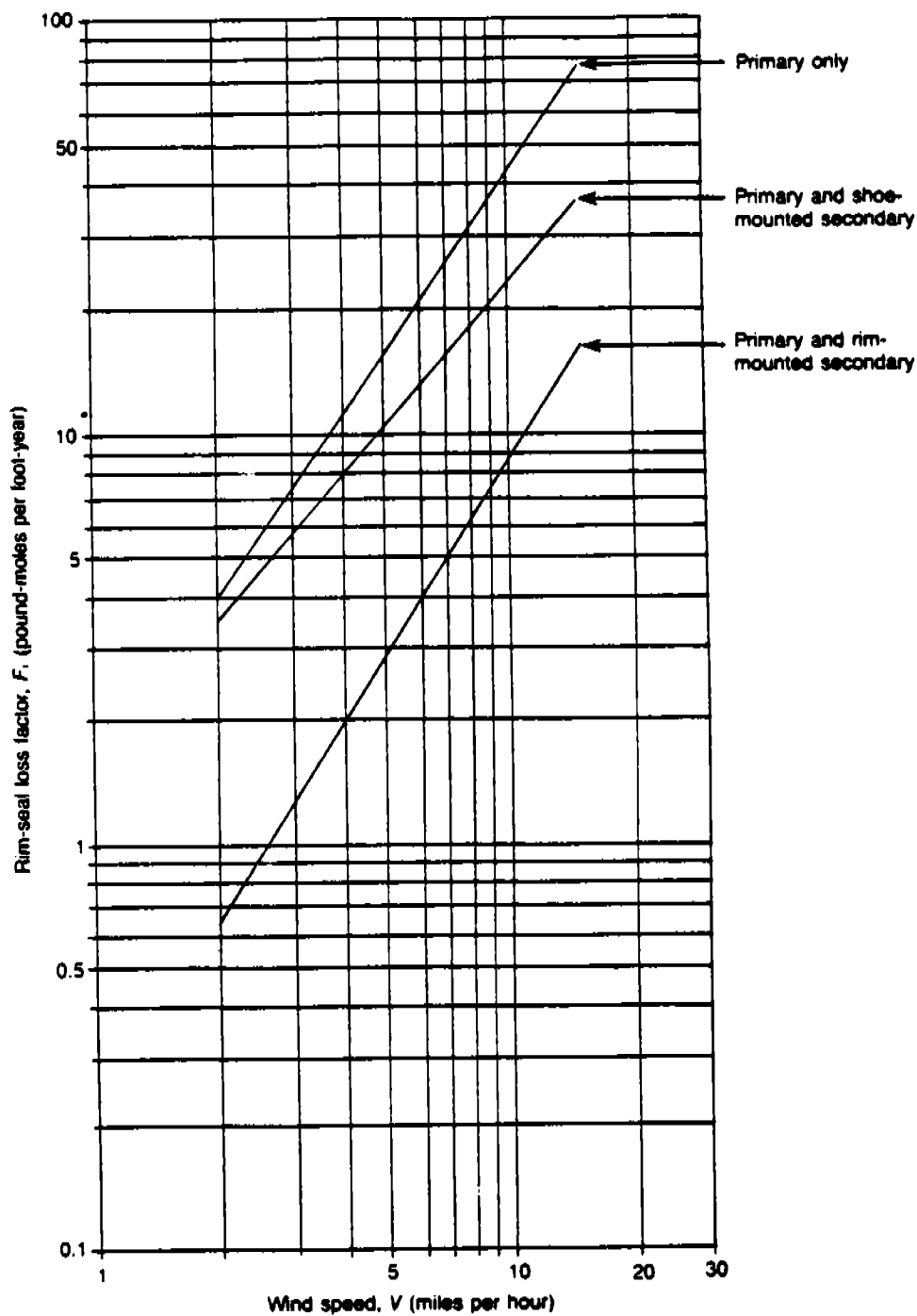
Figure 12.3-11. Rim-seal loss factor for a riveted tank with a mechanical-shoe primary seal.[3]
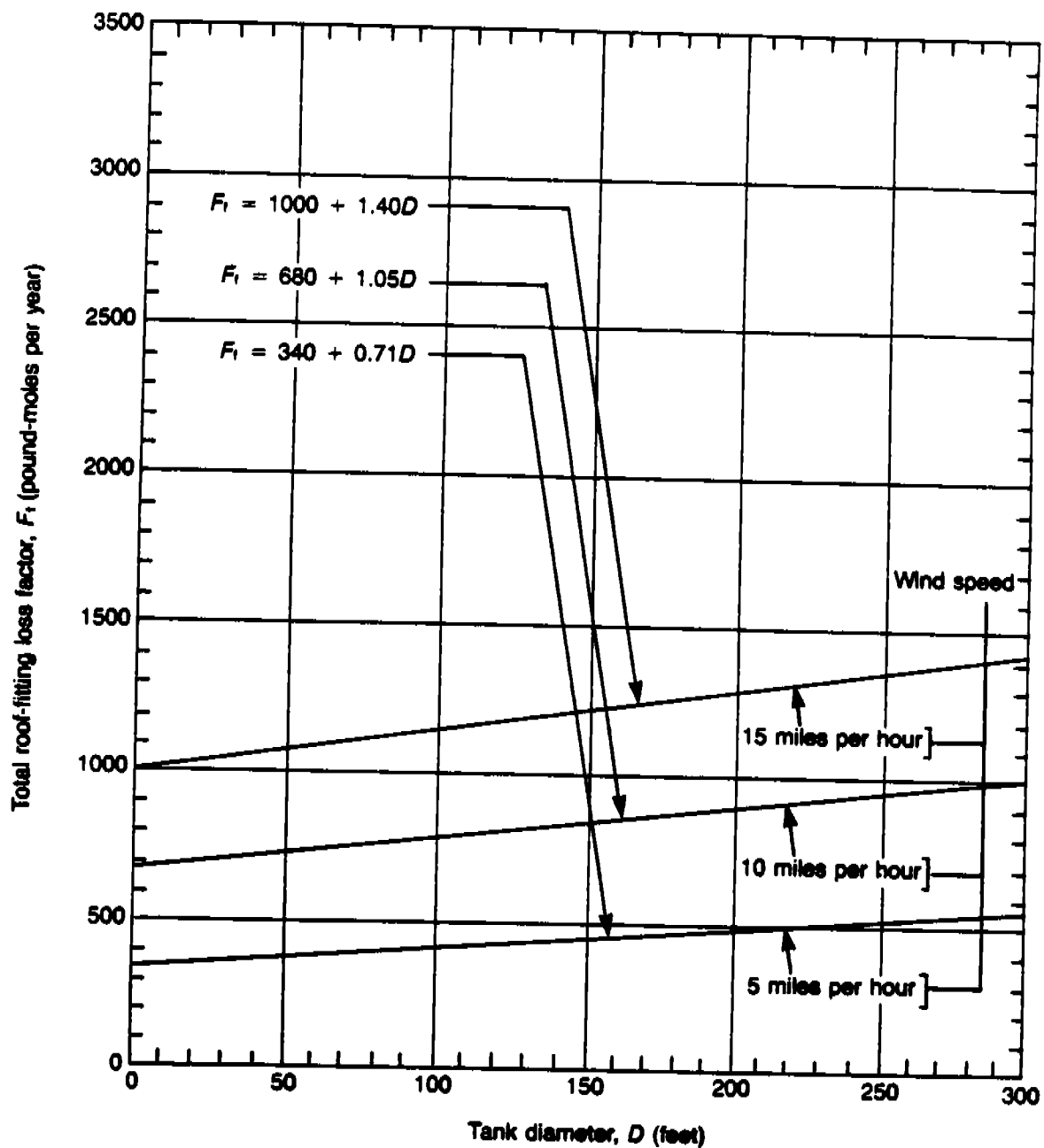
Figure 12.3-12. Total roof-fitting loss factor for typical
fittings on pontoon floating roofs.[3]

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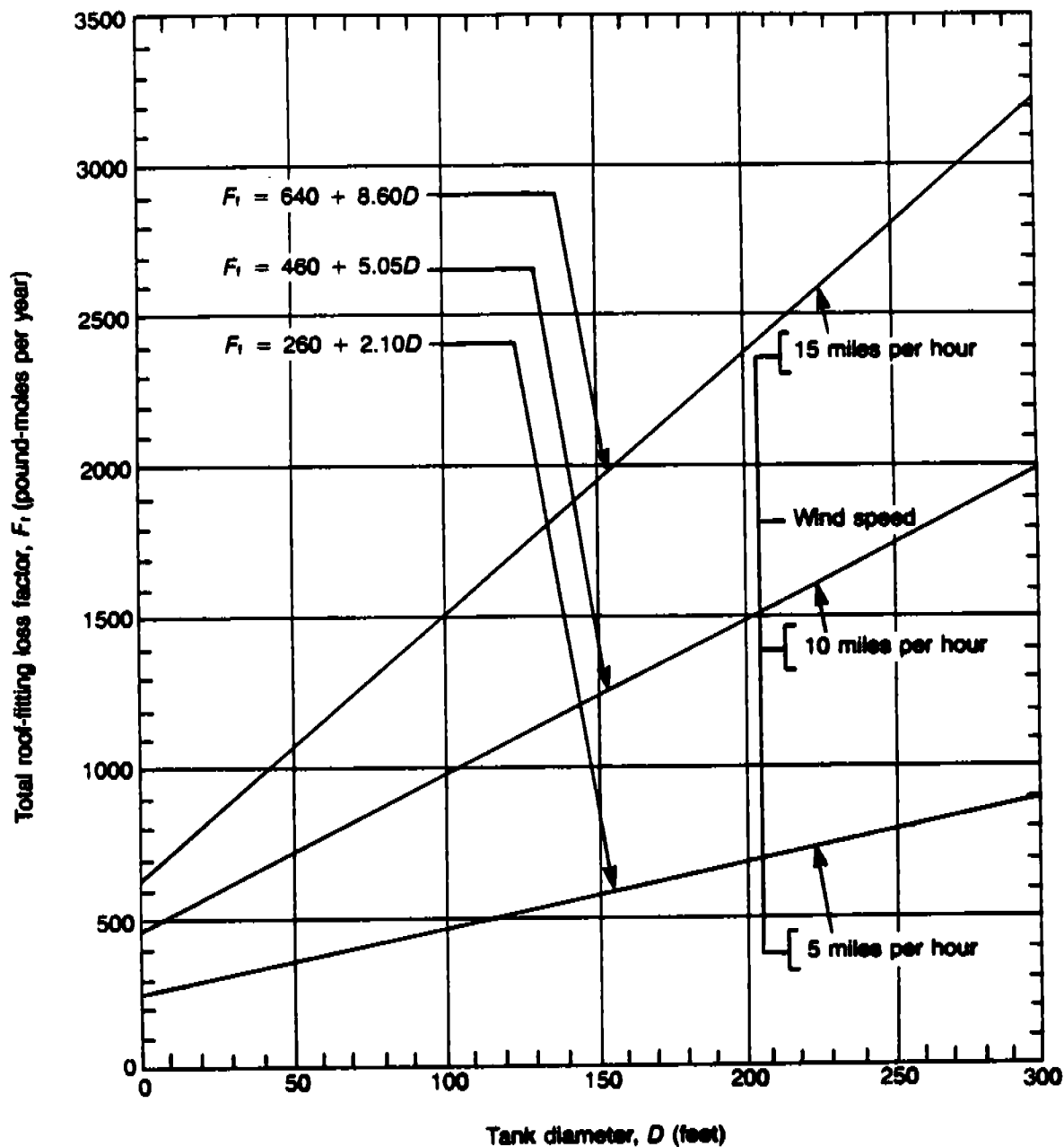
Figure 12.3-13. Total roof-fitting loss factor for typical
fittings on double-deck floating roofs.[3]

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TABLE 12.3-8. RIM-SEAL LOSS FACTORS, K_R and n, FOR EXTERNAL FLOATING ROOF TANKS[a]

Tank construction and rim-seal system	Average-fitting seals	
	K_R [lb-mole/(mph)^n-ft-yr]	n (dimensionless)
Welded tanks		
Mechanical-shoe seal		
Primary only	1.2[b]	1.5[b]
Shoe-mounted secondary	0.8	1.2
Rim-mounted secondary	0.2	1.0
Liquid-mounted resilient-filled seal		
Primary only	1.1	1.0
Weather shield	0.8	0.9
Rim-mounted secondary	0.7	0.4
Vapor-mounted resilient-filled seal		
Primary only	1.2	2.3
Weather shield	0.9	2.2
Rim-mounted secondary	0.2	2.6
Riveted tanks		
Mechanical-shoe seal		
Primary only	1.3	1.5
Shoe-mounted secondary	1.4	1.2
Rim-mounted secondary	0.2	1.6

[a]Reference 3.

[b]If no specific information is available, a welded tank with an average-fitting mechanical-shoe primary seal can be used to represent the most common or typical construction and rim-seal system in use.

TABLE 12.3-9. AVERAGE ANNUAL WIND SPEED (v) FOR FOR SELECTED U.S. LOCATIONS[a]

Location	Wind Speed (mph)	Location	Wind Speed (mph)	Location	Wind Speed (mph)
Alabama		California (continued)		Florida (continued)	
Birmingham	7.2	Eureka	6.8	Pensacola	8.4
Huntsville	8.2	Fresno	6.3	Tallahassee	6.3
Mobile	9.0	Long Beach	6.4	Tampa	8.4
Montgomery	6.6	Los Angeles (City)	6.2	West Palm Beach	9.6
		Los Angeles International			
		Airport	7.5		
		Mount Shasta	5.1	Georgia	
Alaska		Sacramento	7.9	Athens	7.4
Anchorage	6.9	San Diego	6.9	Atlanta	9.1
Annette	10.6	San Francisco (City)	8.7	Augusta	6.5
Barrow	11.8	San Francisco		Columbus	6.7
Barter Island	13.2	Airport	10.6	Macon	7.6
Bethel	12.8	Santa Maria	7.0	Savannah	7.9
Bettles	6.7	Stockton	7.5		
Big Delta	8.2				
Cold Bay	17.0			Hawaii	
Fairbanks	5.4			Hilo	7.2
Gulkana	6.8	Colorado		Honolulu	11.4
Homer	7.6	Colorado Springs	10.1	Kahului	12.8
Juneau	8.3	Denver	8.7	Lihue	12.2
King Salmon	10.8	Grand Junction	8.1		
Kodiak	10.8	Pueblo	8.7		
Kotzebue	13.0				
McGrath	5.1			Idaho	
Nome	10.7	Connecticut		Bosie	8.8
St. Paul Island	17.7	Bridgeport	12.0	Pocatello	10.2
Talkeetna	4.8	Hartford	8.5		
Valdez	6.0				
Yakutat	7.4			Illinois	
		Delaware		Cairo	8.5
		Wilmington	9.1	Chicago	10.3
				Moline	10.0
Arizona				Peoria	10.0
Flagstaff	6.8			Rockford	10.0
Phoenix	6.3	District of Columbia		Springfield	11.2
Tucson	8.3	Dulles Airport	7.4		
Winslow	8.9	National Airport	9.4		
Yuma	7.8			Indiana	
				Evansville	8.1
		Florida		Fort Wayne	10.0
		Apalachicola	7.8	Indianapolis	9.6
Arkansas		Daytona Beach	8.7	South Bend	10.3
Fort Smith	7.6	Fort Myers	8.1		
Little Rock	7.8	Jacksonville	8.0		
		Key West	11.2		
California		Miami	9.3	Iowa	
Bakersfield	6.4	Orlando	8.5	Des Moines	10.9
Blue Canyon	6.8				

TABLE 12.3-9. (Continued)

Location	Wind Speed (mph)	Location	Wind Speed (mph)	Location	Wind Speed (mph)
Iowa (continued)		Michigan (continued)		Nevada	
Sioux City	11.0	Houghton Lake	8.9	Elko	6.0
Waterloo	10.7	Lansing	10.0	Ely	10.3
		Muskegon	10.7	Las Vegas	9.3
		Sault Sainte Marie	9.3	Reno	6.6
Kansas				Winnemucca	8.0
Concordia	12.3				
Dodge City	14.0	Minnesota			
Goodland	12.6	Duluth	11.1	New Hampshire	
Topeka	10.2	International Falls	8.9	Concord	6.7
Wichita	12.3	Minneapolis-Saint Paul	10.6	Mount Washington	35.3
		Rochester	13.1		
		Saint Cloud	8.0		
Kentucky				New Jersey	
Cincinnati Airport	9.1			Atlantic City	10.1
Jackson	7.2	Mississippi		Newark	10.2
Lexington	9.3	Jackson	7.4		
Louisville	8.4	Meridian	6.1		
				New Mexico	
				Albuquerque	9.1
Louisiana		Missouri		Roswell	8.6
Baton Rouge	7.6	Columbia	9.9		
Lake Charles	8.7	Kansas City	10.8		
New Orleans	8.2	Saint Louis	9.7	New York	
Shreveport	8.4	Springfield	10.7	Albany	8.9
				Binghamton	10.3
				Buffalo	12.0
Maine		Montana		New York (Central Park)	9.4
Caribou	11.2	Billings	11.2	New York (JFK Airport)	12.0
Portland	8.8	Glasgow	10.8	New York (La Guardia	
		Great Falls	12.8	Airport)	12.2
		Helena	7.8	Rochester	9.7
Maryland		Kalispell	6.6	Syracuse	9.5
Baltimore	9.2	Missoula	6.2		
				North Carolina	
Massachusetts		Nebraska		Asheville	7.6
Blue Hill Observatory	15.4	Grand Island	11.9	Cape Hatteras	11.1
Boston	12.4	Lincoln	10.4	Charlotte	7.5
Worcester	10.2	Norfolk	11.7	Greensboro-	
		North Platte	10.2	High Point	7.5
		Omaha	10.6	Raleigh	7.8
Michigan		Scotts Bluff	10.6	Wilmington	8.8
Alpena	8.1	Valentine	9.7		
Detroit	10.2			North Dakota	
Flint	10.2			Bismark	10.2
Grand Rapids	9.8				

TABLE 12.3-9. (Continued)

Location	Wind Speed (mph)	Location	Wind Speed (mph)	Location	Wind Speed (mph)
North Dakota (continued)		South Dakota		Washington	
Fargo	12.3	Aberdeen	11.2	Olympia	6.7
Williston	10.1	Huron	11.5	Quillayute	6.1
		Rapid City	11.3	Seattle Int'l. Airport	9.0
Ohio		Sioux Falls	11.1	Spokane	8.9
Akron	9.8			Walls Walls	5.3
Cleveland	10.6	Tennessee		Yakima	7.1
Columbus	8.5	Bristol-Johnson City	5.5		
Dayton	9.9	Chattanooga	6.1	West Virginia	
Mansfield	11.0	Knoxville	7.0	Beckley	9.1
Toledo	9.4	Memphis	8.9	Charleston	6.4
Youngstown	9.9	Nashville	8.0	Elkins	6.2
		Oak Ridge	4.4	Huntington	6.6
Oklahoma					
Oklahoma City	12.4	Texas		Wisconsin	
Tulsa	10.3	Abilene	12.0	Green Bay	10.0
		Amarillo	13.6	La Crosse	8.8
Oregon		Austin	9.2	Madison	9.9
Astoria	8.6	Brownsville	11.5	Milwaukee	11.6
Eugene	7.6	Corpus Christi	12.0		
Medford	4.8	Dalls-Fort Worth	10.8	Wyoming	
Pendleton	8.7	Del Rio	9.9	Casper	12.9
Portland	7.9	El Paso	8.9	Cheyenne	13.0
Salem	7.1	Galveston	11.0	Lander	6.8
Sexton Summit	11.8	Houston	7.9	Sheridan	8.0
		Lubbock	12.4		
		Midland-Odessa	11.1		
Pennsylvania		Port Arthur	9.8		
Allentown	9.2	San Angelo	10.4		
Avoca	8.3	San Antonio	9.3		
Erie	11.3	Victoria	10.1		
Harrisburg	7.6	Waco	11.3		
Philadelphia	9.5	Wichita Falls	11.7		
Pittsburgh Int'l. Airport	9.1				
Williamsport	7.8	Utah			
		Salt Lake City	8.9		
Puerto Rico					
San Juan	8.4	Vermont			
		Burlington	8.9		
Rhode Island					
Providence	10.6	Virginia			
		Lynchburg	7.7		
South Carolina		Norfolk	10.7		
Charleston	8.6	Richmond	7.7		
Columbia	6.9	Roanoke	8.1		
Greenville-Spartanburg	6.9				

Storage of Organic Liquids

TABLE 12.3-10. AVERAGE CLINGAGE FACTORS, C
(Barrels per 1,000 square feet)[a]

Product stored	Shell condition		
	Light rust	Dense rust	Gunite lining
Gasoline	0.0015	0.0075	0.15
Single-component stocks	0.0015	0.0075	0.15
Crude oil	0.0060	0.030	0.60

[a]Reference 3.

Note: If no specific information is available, the values in this table can be assumed to represent the most common or typical condition of tanks currently in use.

TABLE 12.3-11. EXTERNAL FLOATING ROOF-FITTING LOSS FACTORS, K_{Fa}, K_{Fb}, AND m, AND TYPICAL NUMBER OF ROOF FITTINGS, N_F[a]

Fitting type and construction details	Loss Factors			Typical number fittings, N_F
	K_{Fa} (lb-mole/yr)	K_{Fb} [lb-mole/(mph)^m-yr]	m (dimensionless)	
Access hatch (24-inch diameter well)				1
Bolted cover, gasketed	0	0	0[b]	
Unbolted cover, ungasketed	2.7	7.1	1.0	
Unbolted cover, gasketed	2.9	0.41	1.0	
Unslotted guide-pole well (8-inch diameter unslotted pole, 21-inch diameter well)				1
Ungasketed sliding cover	0	67	0.98[b]	
Gasketed sliding cover	0	3.0	1.4	
Slotted guide-pole/sample well (8 inch diameter slotted pole, 21-inch diameter well)				c
Ungasketed sliding cover, without float	0	310	1.2	
Ungasketed sliding cover, with float	0	29	2.0	
Gasketed sliding cover, without float	0	260	1.2	
Gasketed sliding cover, with float	0	8.5	2.4	
Gauge-float well (20-inch diameter)				1
Unbolted cover, ungasketed	2.3	5.9	1.0[b]	
Unbolted cover, gasketed	2.4	0.34	1.0	
Bolted cover, gasketed	0	0	0	
Gauge-hatch/sample well (8-inch diameter)				1
Weighted mechanical actuation, gasketed	0.95	0.14	1.0[b]	
Weighted mechanical actuation, ungasketed	0.91	2.4	1.0	
Vacuum breaker (10-inch diameter well)				N_{F6}(Table 12.3-12)
Weighted mechanical actuation, gasketed	1.2	0.17	1.0[b]	
Weighted mechanical actuation, ungasketed	1.1	3.0	1.0	
Roof drain (3-inch diameter)				N_{F7}(Table 12.3-12)
Open	0	7.0	1.4[d]	
90% closed	0.51	0.81	1.0	
Roof leg (3-inch diameter)				N_{F8}(Table 12.3-13)[e]
Adjustable, pontoon area	1.5	0.20	1.0[b]	
Adjustable, center area	0.25	0.067	1.0[b]	
Adjustable, double-deck roofs	0.25	0.067	1.0	
Fixed	0	0	0	
Roof leg (2-1/2 inch diameter)				N_{F8}(Table 12.3-13)[e]
Adjustable, pontoon area	1.7	0	0	
Adjustable, center area	0.41	0	0	
Adjustable, double-deck roofs	0.41	0	0	
Fixed	0	0	0	

TABLE 12.3-11. (Continued)

Fitting type and construction details	Loss Factors			Typical number fittings, N_F
	K_{Fa} (lb-mole/yr)	K_{Fb} [lb-mole/(mph)^m-yr]	m (dimensionless)	
Rim vent (6-inch diameter)				1[f]
Weighted mechanical actuation, gasketed	0.71	0.10	1.0[b]	
Weighted mechanical actuation, ungasketed	0.68	1.8	1.0	

Note: The roof-fitting loss factors, K_{Fa}, K_{Fb}, and m, may only be used for wind speeds from 2 to 15 miles per hour.

[a] Reference 3.
[b] If no specific information is available, this value can be assumed to represent the most common or typical roof fitting currently in use.
[c] A slotted guide-pole/sample well is an optional fitting and is not typically used.
[d] Roof drains that drain excess rainwater into the product are not used on pontoon floating roofs. They are, however, used on double-deck floating roofs and are typically left open.
[e] The most common roof leg diameter is 3 inches. The loss factors for 2-1/2 inch diameter roof legs are provided for use if this smaller size roof leg is used on a particular floating roof.
[f] Rim vents are used only with mechanical-shoe primary seals.

TABLE 12.3-12. EXTERNAL FLOATING ROOF TANKS: TYPICAL NUMBER OF VACUUM BREAKERS, N_{F6}, AND ROOF DRAINS, N_{F7}[a]

Tank diameter D (feet)[b]	Number of vacuum breakers, N_{F6}		Number of roof drains, N_{F7} (double-deck roof)[c]
	Pontoon roof	Double-deck roof	
50	1	1	1
100	1	1	1
150	2	2	2
200	3	2	3
250	4	3	5
300	5	3	7
350	6	4	--
400	7	4	--

Note: This table was derived from a survey of users and manufacturers. The actual number of vacuum breakers may vary greatly depending on throughput and manufacturing prerogatives. The actual number of roof drains may also vary greatly depending on the design rainfall and manufacturing prerogatives. For tanks more than 300 feet in diameter, actual tank data or the manufacturer's recommendations may be needed for the number of roof drains. This table should not supersede information based on actual tank data.

[a]Reference 3.
[b]If the actual diameter is between the diameters listed, the closest diameter listed should be used. If the actual diameter is midway between the diameters listed, the next larger diameter should be used.
[c]Roof drains that drain excess rainwater into the product are not used on pontoon floating roofs. They are, however, used on double-deck floating roofs and are typically left open.

TABLE 12.3-13. EXTERNAL FLOATING ROOF TANKS: TYPICAL NUMBER OF ROOF LEGS, N_{FS} [a]

Tank diameter, D (feet)[b]	Pontoon roof		Number of legs on double-deck roof
	Number of pontoon legs	Number of center legs	
30	4	2	6
40	4	4	7
50	6	6	8
60	9	7	10
70	13	9	13
80	15	10	16
90	16	12	20
100	17	16	25
110	18	20	29
120	19	24	34
130	20	28	40
140	21	33	46
150	23	38	52
160	26	42	58
170	27	49	66
180	28	56	74
190	29	62	82
200	30	69	90
210	31	77	98
220	32	83	107
230	33	92	115
240	34	101	127
250	35	109	138
260	36	118	149
270	36	128	162
280	37	138	173
290	38	148	186
300	38	156	200
310	39	168	213
320	39	179	226
330	40	190	240
340	41	202	255
350	42	213	270

TABLE 12.3-13. (Continued)

Tank diameter, D (feet)[b]	Pontoon roof		Number of legs on double-deck roof
	Number of pontoon legs	Number of center legs	
360	44	226	285
370	45	238	300
380	46	252	315
390	47	266	330
400	48	281	345

Note: This table was derived from a survey of users and manufacturers. The actual number of roof legs may vary greatly depending on age, style of floating roof, loading specifications, and manufacturing prerogatives. This table should not supersede information based on actual tank data.

[a]Reference 3.
[b]If the actual diameter is between the diameters listed, the closest diameter listed should be used. If the actual diameter is midway between the diameters listed, the next larger diameter should be used.

12.3.3 Total Losses From Internal Floating Roof Tanks[4]

Total internal floating roof tank emissions are the sum of rim seal, withdrawal, deck fitting, and deck seam losses.

The equations provided in this section apply only to freely vented internal floating roof tanks. These equations are not intended to estimate losses from closed internal floating roof tanks (tanks vented only through a pressure/vacuum vent).

Emissions from internal floating roof tanks may be estimated as:

$$L_T = L_R + L_{WD} + L_F + L_D \tag{3-1}$$

where:

L_T = total loss, lb/yr

L_R = rim seal loss, lb/yr; see Equation 3-2

L_{WD} = withdrawal loss, lb/yr; see Equation 3-4

L_F = deck fitting loss, lb/yr; see Equation 3-5

L_D = deck seam loss, lb/yr, see Equation 3-6

Rim Seal Loss - Rim seal losses from floating roof tanks can be estimated by the following equation:

$$L_R = K_R P^* D M_V K_C \tag{3-2}$$

where:

L_R = rim seal loss, lb/yr

K_R = seal factor, lb-mole/(ft-yr); see Table 12.3-14

P^* = vapor pressure function, dimensionless; see Note 2 to Equation 2-2

$$P^* = \frac{P_{VA}/P_A}{[1 + (1 - [P_{VA}/P_A])^{0.5}]^2} \tag{3-3}$$

where: P_A and P_{VA} are as defined for Equation 2-3

D = tank diameter, ft

M_V = average vapor molecular weight, lb/lb-mole; see Note 1 to Equation 1-9

K_C = product factor; K_C = 0.4 for crude oils, K_C = 1.0 for all other organic liquids

Withdrawal Loss - The withdrawal loss from internal floating roof storage tanks can be estimated using Equation 3-4:

$$L_{WD} = \frac{(0.943)QCW_L}{D} [1 + (\frac{N_C F_C}{D})]$$ (3-4)

where:

N_C = number of columns, dimensionless; see Note 1

F_C = effective column diameter, ft (column perimeter [ft])/π); see Note 2

0.943 = constant, 1,000 ft^3 x gal/bbl^2

L_{WD}, Q, C, W_L, and D are as defined for Equation 2-4

Notes:

1. For a self-supporting fixed roof or an external floating roof tank:

N_C = 0.

For a column-supported fixed roof:

N_C = use tank-specific information or see Table 12.3-15.

2. Use tank-specific effective column diameter or

F_C = 1.1 for 9-inch by 7-inch built-up columns, 0.7 for 8-inch-diameter pipe columns, and 1.0 if column construction details are not known

Deck Fitting Losses - Fitting losses from internal floating roof tanks can be estimated by the following equation:

$$L_F = F_F P^* M_v K_C$$ (3-5)

where:

F_F = total deck fitting loss factor, lb-mol/yr

$$= [(N_{F1}K_{F1}) + (N_{F2}K_{F2})...+(N_{F_{nF}}K_{F_{nF}})]$$

where:

N_{F_i} = number of deck fittings of a particular type (i = 0, 1, 2, ..., n_f), dimensionless; see Table 12.3-16[4]

K_{F_i} = deck fitting loss factor for a particular type fitting (i = 0, 1, 2, ..., n_f), lb-mol/yr; see Table 12.3-16[4]

n_f = total number of different types of fittings

P^*, M_V, and K_C are as defined in Equations 2-2 and 2-5.

The value of F_F may be calculated by using actual tank-specific data for the number of each fitting type (N_F) and then multiplying by the fitting loss factor for each fitting (K_F). Values of fitting loss factors and typical number of fittings are presented in Table 12.3-16. Where tank-specific data for the number and kind of deck fittings are unavailable, then F_F can be approximated according to tank diameter. Figures 12.3-14 and 12.3-15 present F_F plotted against tank diameter for column-supported fixed roofs and self-supported fixed roofs, respectively.

<u>Deck Seam Loss</u> - Welded internal floating roof tanks do not have deck seam losses. Tanks with bolted decks may have deck seam losses. Deck seam loss can be estimated by the following equation:

$$L_D = K_D S_D D^2 P^* M_V K_C \tag{3-6}$$

where:

K_D = deck seam loss per unit seam length factor, lb-mol/ft-yr

= 0.0 for welded deck

= 0.34 for bolted deck; see Note

S_D = deck seam length factor, ft/ft^2
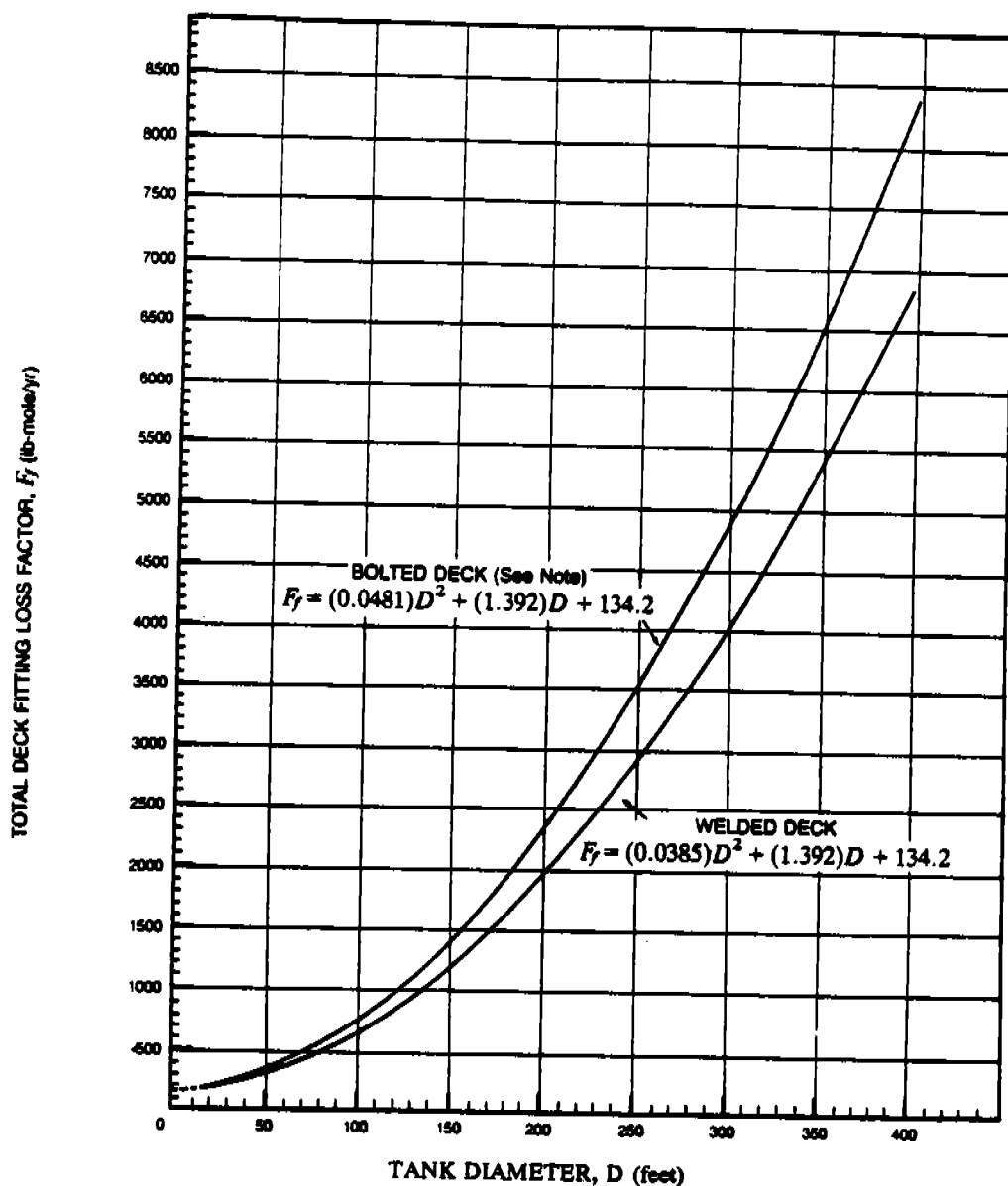
$$= \frac{L_{seam}}{A_{deck}}$$

where:

L_{seam} = total length of deck seams, ft

$$A_{deck} = \text{area of deck, ft}^2 = \pi D^2/4$$

D, P*, M_V, and K_C are as defined for Equation 2.2

If the total length of the deck seam is not known, Table 12.3-17 can be used to determine S_D. For a deck constructed from continuous metal sheets with a 7-ft spacing between the seams, a value of 0.14 ft/ft^2 can be used. A value of 0.33 ft/ft^2 can be used for S_D when a deck is constructed from rectangular panels 5 ft by 7.5 ft. Where tank-specific data concerning width of deck sheets or size of deck panels are unavailable, a default value for S_D can be assigned. A value of 0.20 ft/ft^2 can be assumed to represent the most common bolted decks currently in use.
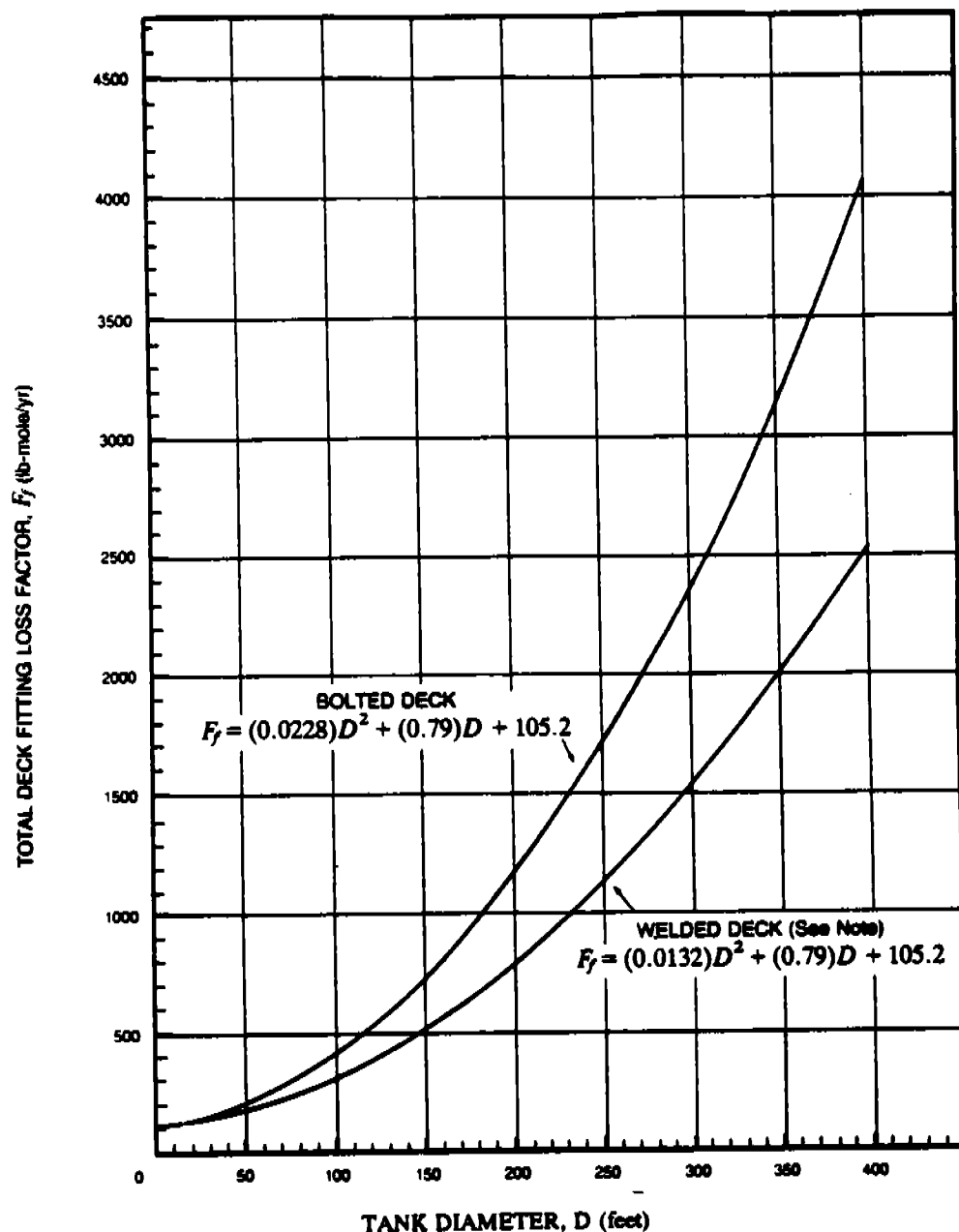
Note: Recently vendors of bolted decks have been using various techniques in an effort to reduce deck seam losses. However, emission factors are not currently available in AP-42 that represent the emission reduction achieved by these techniques. Some vendors have developed specific factors for their deck designs; however, use of these factors is not recommended until approval has been obtained from the governing regulatory agency or permitting authority.

Figure 12.3-14. Approximated total deck fitting loss factors (F_f) for typical
fittings in tanks with column-supported fixed roofs and either a bolted deck or
a welded deck. This figure is to be used only when tank-specific data on the
number and kind of deck fittings are unavailable.[4]

The figure shows a graph of TOTAL DECK FITTING LOSS FACTOR, F_f (lb-mole/yr) versus TANK DIAMETER, D (feet), with two curves:

BOLTED DECK (See Note)
$$F_f = (0.0481)D^2 + (1.392)D + 134.2$$

WELDED DECK
$$F_f = (0.0385)D^2 + (1.392)D + 134.2$$

Basis: Fittings include: (1) access hatch with ungasketed, unbolted cover, (2) built-up column wells with ungasketed unbolted cover, (3) adjustable deck legs; (4) gauge float well with ungasketed, unbolted cover, (5) ladder well with ungasketed sliding cover; (6) sample well with slit fabric seal (10% open area); (7) 1-inch-diameter stub drains (only on bolted deck); and (8) vacuum breaker with gasketed weighted mechanical actuation. This basis was derived from a survey of users and manufacturers. Other fittings may be typically used within particular companies or organizations to reflect standards and/or specifications of that group. This figure should not supersede information based on actual tank data.

NOTE: If no specification information is available, assume bolted decks are the most common/typical type currently in use in tanks with column-supported fixed roofs.

Figure 12.3-15. Approximated total deck fitting loss factors (F_f) for typical
fittings in tanks with self-supporting fixed roofs and either a
bolted deck or a welded deck. This figure is to be used
only when tank-specific data on the number and kind of deck
fittings are unavailable.[4]

The graph shows two curves with the following equations:

BOLTED DECK
$$F_f = (0.0228)D^2 + (0.79)D + 105.2$$

WELDED DECK (See Note)
$$F_f = (0.0132)D^2 + (0.79)D + 105.2$$

Axes: TOTAL DECK FITTING LOSS FACTOR, F_f (lb-mole/yr) vs. TANK DIAMETER, D (feet)

Basis: Fittings include: (1) access hatch with ungasketed, unbolted cover, (2) adjustable deck legs; (3) gauge float well with ungasketed, unbolted cover, (4) sample well with slit fabric seal (10% open area); (5) 1-inch-diameter stub drains (only on bolted deck); and (6) vacuum breaker with gasketed weighted mechanical actuation. This basis was derived from a survey of users and manufacturers. Other fittings may be typically used within particular companies or organizations to reflect standards and/or specifications of that group. This figure should not supersede information based on actual tank data.

NOTE: If no specification information is available, assume bolted decks are the most common/typical type currently in use in tanks with column-supported fixed roofs.

TABLE 12.3-14. INTERNAL FLOATING ROOF RIM SEAL LOSS FACTORS (K_R)[a]

Rim seal system description	K_R (lb-mole/ft•yr)
	Average
Vapor-mounted primary seal only	6.7[b]
Liquid-mounted primary seal only	3.0
Vapor-mounted primary seal plus secondary seal	2.5
Liquid-mounted primary seal plus secondary seal	1.6

[a]Reference 4.
[b]If no specific information is available, this value can be assumed to represent the most common/typical rim seal system currently in use.

TABLE 12.3-15. TYPICAL NUMBER OF COLUMNS AS A FUNCTION OF TANK DIAMETER FOR INTERNAL FLOATING ROOF TANKS WITH COLUMN-SUPPORTED FIXED ROOFS[a]

Tank diameter range D, (ft)	Typical number of columns, N_C
$0 < D \leq 85$	1
$85 < D \leq 100$	6
$100 < D \leq 120$	7
$120 < D \leq 135$	8
$135 < D \leq 150$	9
$150 < D \leq 170$	16
$170 < D \leq 190$	19
$190 < D \leq 220$	22
$220 < D \leq 235$	31
$235 < D \leq 270$	37
$270 < D \leq 275$	43
$275 < D \leq 290$	49
$290 < D \leq 330$	61
$330 < D \leq 360$	71
$360 < D \leq 400$	81

[a]Reference 4. This table was derived from a survey of users and manufacturers. The actual number of columns in a particular tank may vary greatly with age, fixed roof style, loading specifications, and manufacturing prerogatives. Data in this table should not supersede information on actual tanks.

TABLE 12.3-16. SUMMARY OF INTERNAL FLOATING DECK FITTING LOSS FACTORS (K_F) AND TYPICAL NUMBER OF FITTINGS (N_F)[a]

Deck fitting type	Deck fitting loss factor, K_F (lb-mole/yr)	Typical number of fittings, N_F
Access hatch (24-inch diameter)		
Bolted cover, gasketed	1.6	1
Unbolted cover, gasketed	11	
Unbolted cover, ungasketed	25[b]	
Automatic gauge float well		
Bolted cover, gasketed	5.1	1
Unbolted cover, gasketed	15	
Unbolted cover, ungasketed	28[b]	
Column well (24-inch diameter)[c]		
Builtup column-sliding cover, gasketed	33	(see Table 12.3-15)
Builtup column-sliding cover, ungasketed	47[b]	
Pipe column-flexible fabric sleeve seal	10	
Pipe column-sliding cover, gasketed	19	
Pipe column-sliding cover, ungasketed	32	
Ladder well (36-inch diameter)[c]		
Sliding cover, gasketed	56	1[f]
Sliding cover, ungasketed	76[b]	
Roof leg or hanger well		
Adjustable	7.9[b]	$(5+\dfrac{D}{10}+\dfrac{D^2}{600})^c$
Fixed	0	
Sample pipe or well (24-inch diameter)		
Slotted pipe-sliding cover, gasketed	44	1
Slotted pipe-sliding cover, ungasketed	57	
Sample well-slit fabric seal 10% open area	12[b]	
Stub drain (1-inch diameter)[e]	1.2	$(\dfrac{D^2}{125})^{c\ d}$

TABLE 12.3-16. (Continued)

Deck fitting type	Deck fitting loss factor, K_F (lb-mole/yr)	Typical number of fittings, N_F
Vacuum breaker (10-inch diameter)		
Weighted mechanical actuation, gasketed	0.7[b]	1
Weighted mechanical actuation, ungasketed	0.9	

[a]Reference 4.
[b]If no specific information is available, this value can be assumed to represent the most common/typical deck fittings currently used.
[c]Column wells and ladder wells are not typically used with self-supported roofs.
[d]D = tank diameter, (ft).
[e]Not used on welded contact internal floating decks.
[f]Not typically used on tanks with self-supporting fixed roofs.

TABLE 12.3-17. DECK SEAM LENGTH FACTORS (S_D) FOR TYPICAL DECK CONSTRUCTIONS FOR INTERNAL FLOATING ROOF TANKS[a]

Deck construction	Typical deck seam length factor, S_D (ft/ft^2)
Continuous sheet construction[b]	
5 ft wide 6 ft wide 7 ft wide	0.20[c] 0.17 0.14
Panel construction[d]	
5 x 7.5 ft rectangular 5 x 12 ft rectangular	0.33 0.28

[a]Reference 4. Deck seam loss applies to bolted decks only.

[b]$S_D = 1/W$, where W = sheet width (ft).

[c]If no specific information is available, this factor can be assumed to represent the most common bolted decks currently in use.

[d]$S_D = (L+W)/LW$, where W = panel width (ft) and L = panel length (ft).

12.3.4 Variable Vapor Space Tanks[13]

Variable vapor space filling losses result when vapor is displaced by liquid during filling operations. Since the variable vapor space tank has an expandable vapor storage capacity, this loss is not as large as the filling loss associated with fixed roof tanks. Loss of vapor occurs only when the tank's vapor storage capacity is exceeded.

Variable vapor space system filling losses can be estimated from:

$$L_V = (2.40 \times 10^{-2}) M_V P_{VA}/V_1 [(V_1) - (0.25 V_2 N_2)] \tag{4-1}$$

where:

L_V = variable vapor space filling loss, lb/1,000 gal throughput

M_V = molecular weight of vapor in storage tank, lb/lb-mole; see Note 1 to Equation 1-9

P_{VA} = true vapor pressure at the daily average liquid surface temperature, psia; see Notes 1 and 2 to Equation 1-9

V_1 = volume of liquid pumped into system, throughput, bbl/yr

V_2 = volume expansion capacity of system, bbl; see Note 1

N_2 = number of transfers into system, dimensionless; see Note 2

Notes:

1. V_2 is the volume expansion capacity of the variable vapor space achieved by roof lifting or diaphragm flexing.

2. N_2 is the number of transfers into the system during the time period that corresponds to a throughput of V_1.

The accuracy of Equation 4-1 is not documented. Special tank operating conditions may result in actual losses significantly different from the estimates provided by Equation 4-1. It should also be noted that, although not developed for use with heavier petroleum liquids such as kerosenes and fuel oils, the equation is recommended for use with heavier petroleum liquids in the absence of better data.

12.3.5 Pressure Tanks

Losses occur during withdrawal and filling operations in low-pressure (2.5 to 15 psig) tanks when atmospheric venting occurs. High-pressure tanks are considered closed systems, with virtually no emissions. Vapor recovery systems are often found on low-pressure tanks. Fugitive losses are also associated with pressure tanks and their equipment, but with proper

system maintenance, these losses are considered insignificant. No appropriate correlations are available to estimate vapor losses from pressure tanks.

12.3.6 Variations of Emission Estimation Procedures

All of the emission estimation procedures presented in Section 12.3 can be used to estimate emissions for shorter time periods by manipulating the inputs to the equations for the time period in question. For all of the emission estimation procedures, the daily average liquid surface temperature should be based on the appropriate temperature and solar insolation data for the time period over which the estimate is to be evaluated. The subsequent calculation of the vapor pressure should be based on the corrected daily liquid surface temperature. For example, emission calculations for the month of June would be based only on the meteorological data for June. It is important to note that a 1-month time frame is recommended as the shortest time period of which emissions should be estimated.

In addition to the temperature and vapor pressure corrections, the constant in the standing storage loss equation for fixed roof tanks would need to be revised based on the actual time frame used. The constant, 365, is based on the number of days in a year. To change the equation for a different time period, the constant should be changed to the appropriate number of days in the time period for which emissions are being estimated. The only change that would need to be made to the working loss equation for fixed roof tanks would be to change the throughput per year to the throughput during the time period for which emissions are being estimated.

Other than changing the meteorological data and the vapor pressure data, the only changes needed for the floating roof rim seal, fitting, and deck seam losses would be to modify the time frame by dividing the individual losses by the appropriate number of days or months. The only change to the withdrawal losses would be to change the throughput to the throughput for the time period for which emissions are being estimated.

Another variation that is frequently made to the emission estimation procedures is an adjustment in the working or withdrawal loss equations if the tank is operated as a surge tank or constant level tank. For constant level tanks or surge tanks where the throughput and turnovers are high but the liquid level in the tank remains relatively constant, the actual throughput or turnovers should not be used in the working loss or withdrawal loss equations. For these tanks, the turnovers should be estimated by determining the average change in the liquid height. The average change in height should then be divided by the total shell height. This estimated turnover value should then be multiplied by the tank volume to obtain the net throughput for the loss equations. Alternatively, a default turnover rate of four could be used based on data from these type tanks.

12.4 HAZARDOUS AIR POLLUTANTS (HAP) SPECIATION METHODOLOGY

In some cases it may be important to know the annual emission rate for a component (e.g., HAP) of a stored liquid mixture. There are two basic approaches that can be used to estimate emissions for a single component of a stored liquid mixture. One approach involves calculating the total losses based upon the known physical properties of the mixture (i.e., gasoline) and then determining the individual component losses by multiplying the total loss by the weight fraction of the desired component. The second approach is similar to the first approach except that the mixture properties are unknown; therefore, the mixture properties are first determined based on the composition of the liquid mixture.

Case 1--If the physical properties of the mixture are known (P_{VA}, M_V, M_L and W_L), the total losses from the tank should be estimated using the procedures described previously for the particular tank type. The component losses are then determined from either Equation 5-1 or 5-2. For fixed roof tanks, the emission rate for each individual component can be estimated by:

$$L_{T_i} = (Z_{i,V})(L_T) \tag{5-1}$$

where:

L_{T_i} = emission rate of component i, lb/yr

$Z_{i,V}$ = weight fraction of component i in the vapor, lb/lb

L_T = total losses, lb/yr

For floating roof tanks, the emission rate for each individual component can be estimated by:

$$L_{T,i} = (Z_{i,V}) (L_R + L_F + L_D) + (Z_{i,L}) (L_{WD}) \tag{5-2}$$

where:

$L_{T,i}$ = emission rate of component i, lb/yr

$Z_{i,V}$ = weight fraction of component i in the vapor, lb/lb

L_R = rim seal losses, lb/yr

L_F = roof fitting losses, lb/yr

L_D = deck seam losses, lb/yr

$Z_{i,L}$ = weight fraction of component i in the liquid, lb/lb

L_{WD} = withdrawal losses, lb/yr

If Equation 5-1 is used in place of Equation 5-2 for floating roof tanks, the value obtained will be approximately the same value as that achieved with Equation 5-2 because withdrawal losses are typically minimal for floating roof tanks.

In order to use Equations 5-1 and 5-2, the weight fraction of the desired component in the liquid and vapor phase is needed. The liquid weight fraction of the desired component is typically known or can be readily calculated for most mixtures. In order to calculate the weight fraction in the vapor phase, Raoult's Law must first be used to determine the partial pressure of the component. The partial pressure of the component can then be divided by the total vapor pressure of the mixture to determine the mole fraction of the component in the vapor phase. Raoult's Law states that the mole fraction of the component in the liquid (x_i) multiplied by the vapor pressure of the pure component (at the daily average liquid surface temperature) (P) is equal to the partial pressure (P_i) of that component:

$$P_i = (P)(x_i) \tag{5-3}$$

where:

P_i = partial pressure of component i, psia

P = vapor pressure of pure component i at the daily average liquid surface temperature, psia

x_i = liquid mole fraction, lb-mole/lb-mole

The vapor pressure of each component can be calculated from Antoine's equation or found in standard references, as shown in Section 12.3.1. In order to use Equation 5-3, the liquid mole fraction must be determined from the liquid weight fraction by:

$$x_i = (Z_{i,L})(M_L) / (M_i) \tag{5-4}$$

where:

x_i = liquid mole fraction of component i, lb-mole/lb-mole

$Z_{i,L}$ = weight fraction of component i, lb/lb

M_L = molecular weight of liquid stock, lb/lb-mole

M_i = molecular weight of component i, lb/lb-mole

If the molecular weight of the liquid is not known, the liquid mole fraction can be determined by assuming a total weight of the liquid mixture (see Example 1 in Section 12.5).

The liquid mole fraction and the vapor pressure of the component at the daily average liquid surface temperature can then be substituted into Equation 5-3 to obtain the partial pressure of the component. The vapor mole fraction of the component can be determined from the following equation:

$$y_i = \frac{P_i}{P_{VA}}$$ (5-5)

where:

y_i = vapor mole fraction of component i, lb-mole/lb-mole

P_i = partial pressure of component i, psia

P_{VA} = total vapor pressure of liquid mixture, psia

The weight fractions in the vapor phase are calculated from the mole fractions in the vapor phase.

$$Z_{i,V} = \frac{y_i M_i}{M_V}$$ (5-6)

where:

$Z_{i,V}$ = vapor weight fraction of component i, lb/lb

y_i = vapor mole fraction of component i, lb/lb-mole

M_i = molecular weight of component i, lb/lb-mole

M_V = molecular weight of vapor stock, lb/lb-mole

The liquid and vapor weight fractions of each desired component and the total losses can be substituted into either Equation 5-1 or 5-2 to estimate the individual component losses.

Case 2--For cases where the mixture properties are unknown but the composition of the liquid is known (i.e., nonpetroleum organic mixtures), the equations presented above can be used to obtain a reasonable estimate of the physical properties of the mixture. For nonaqueous organic mixtures, Equation 5-3 can be used to determine the partial pressure of each component. If Equation 5-4 is used to determine the liquid mole fractions, the molecular weight of the liquid stock must be known. If the molecular weight of the liquid stock is unknown, then the liquid mole fractions can be determined by assuming a weight basis and calculating the number of moles (see Example 1 in Section 12.5). The partial pressure of each component can then be determined from Equation 5-3.

For special cases, such as wastewater, where the liquid mixture is a dilute aqueous solution, Henry's Law should be used instead of Raoult's Law in calculating total losses. Henry's Law states that the mole fraction of the component in the liquid phase (x_i) multiplied by the Henry's Law constant for the component in the mixture is equal to the partial pressure (P_i) for that component. For wastewater, Henry's Law constants are typically provided in the form of atm•m³/g-mole. Therefore, the appropriate from of Henry's Law equation is:

$$P_i = (H_A) (C_i) \qquad (5\text{-}7)$$

where:

P_i = partial pressure of component i, atm

H_A = Henry's Law constant for component i, atm•m³/g-mole

C_i = concentration of component i in the wastewater, g-mole/m³; see Note

Section 4.13 of AP-42 presents Henry's Law constants for selected organic liquids. The partial pressure calculated from Equation 5-7 will need to be converted from atmospheres to psia (1 atm = 14.696 psia).

Note: Typically wastewater concentrations are given in mg/liter, which is equivalent to g/m³. To convert the concentrations to g-mole/m³ divide the concentration by the molecular weight of the component.

The total vapor pressure of the mixture can be calculated from the sum of the partial pressures:

$$P_{VA} = \Sigma P_i \qquad (5\text{-}8)$$

where:

P_{VA} = vapor pressure at daily average liquid surface temperature, psia

P_i = partial pressure of component i, psia

This procedure can be used to determine the vapor pressure at any temperature. After computing the total vapor pressure, the mole fractions in the vapor phase are calculated using Equation 5-5. The vapor mole fractions are used to calculate the molecular weight of the vapor, M_V. The molecular weight of the vapor can be calculated by:

$$M_V = \Sigma M_i y_i \qquad (5\text{-}9)$$

where:

M_V = molecular weight of the vapor, lb/lb-mole

M_i = molecular weight of component i, lb/lb-mole

12.5 SAMPLE CALCULATIONS[14]

Example 1 - Chemical Mixture in a Fixed Roof Tank

Determine the yearly emission rate of the total product mixture and each component for a chemical mixture stored in a vertical cone roof tank in Denver, Colorado. The chemical mixture contains (for every 3,171 lb of mixture) 2,812 lb of benzene, 258 lb of toluene, and 101 lb of cyclohexane. The tank is 6 ft in diameter, 12 ft high, usually holds about 8 ft of product, and is painted white. The tank working volume is 1,690 gallons. The number of turnovers per year for the tank is five (i.e., the throughput of the tank is 8,450 gal/yr).

Solution

1. <u>Determine tank type</u>. The tank is a fixed-cone roof, vertical tank.

2. <u>Determine estimating methodology</u>. The product is made up of three organic liquids, all of which are miscible in each other, which makes a homogenous mixture if the material is well mixed. The tank emission rate will be based upon the properties of the mixture. Raoult's law (as discussed in the HAP Speciation Section) is assumed to apply to the mixture and will be used to determine the properties of the mixture.

3. <u>Select equations to be used</u>. For a vertical, fixed roof storage tank, the following equations apply:

$$L_T = L_S + L_W \tag{1-1}$$

$$L_S = 365 \, W_V V_V K_E K_S \tag{1-2}$$

$$L_W = 0.0010 \, M_V P_{VA} Q K_N K_P \tag{1-23}$$

where:

L_T = total loss, lb/yr

L_S = standing storage loss, lb/yr

L_W = working loss, lb/yr

V_V = tank vapor space volume, ft^3

$$V_v = \pi/4 \, D^2 H_{VO} \tag{1-3}$$

W_V = vapor density, lb/ft^3

$$W_v = \frac{M_v P_{VA}}{RT_{LA}} \qquad \text{(1-9)}$$

K_E = vapor space expansion factor, dimensionless

$$K_E = \frac{\Delta T_V}{T_{LA}} + \frac{\Delta P_V - \Delta P_B}{P_A - P_{VA}} \qquad \text{(1-16)}$$

K_S = vented vapor space saturation factor, dimensionless

$$K_S = \frac{1}{1 + 0.053 \, P_{VA} H_{VO}} \qquad \text{(1-22)}$$

D = diameter, ft

H_{VO} = vapor space outage, ft

M_V = molecular weight of vapor, lb/lb-mole

P_{VA} = vapor pressure at the daily average liquid surface temperature, psia

T_{LA} = daily average liquid surface temperature, °R

ΔT_V = daily vapor temperature range, °R

ΔP_V = daily vapor pressure range, psia

ΔP_B = breather vent pressure setting range, psi

P_A = atmospheric pressure, psia

Q = annual net throughput, bbl/yr

K_N = working loss turnover factor, dimensionless

K_P = working loss product factor, dimensionless

y_i = vapor mole fraction of component i, lb-mole/lb-mole

Another variable that may need to be calculated before estimating the total losses if it is not available in a standard reference is the density of the liquid, W_L. If the density of the liquid is unknown, it can be estimated based on the liquid weight fractions of each component (see Section 12.5, Example 3).

All of the mixture properties are now known (P_{VA}, M_V, and W_L), therefore, these values can be inputted into the emission estimation procedures outlined in Section 12.3 to estimate total losses. After calculating the total losses, the component losses can be calculated by using either Equation 5-1 or 5-2. Prior to calculating component losses, Equation 5-6 must be used to determine the vapor weight fractions of each component.

EMISSION FACTORS

4. Calculate each component of the standing storage loss and working loss functions.

   a. Tank vapor space volume, V_V.

$$V_V = \pi/4 \; D^2 \; H_{VO} \qquad (1\text{-}3)$$

    $D = 6$ ft (given)

For a cone roof, the vapor space outage, H_{VO} is calculated by:

$$H_{VO} = H_S - H_L + H_{RO} \qquad (1\text{-}4)$$

    $H_S = $ tank shell height, 12 ft (given)

    $H_L = $ stock liquid height, 8 ft (given)

    $H_{RO} = $ roof outage, $1/3 \; H_R = 1/3(S_R)(R_S)$ (1-6)

    $S_R = $ tank cone roof slope, 0.0625 ft/ft (given) (see Note 1 to Equation 1-4)

    $R_S = $ tank shell radius $= 1/2 \; D = 1/2 \; (6) = 3$

Substituting values in Equation 1-6 yields,

$$H_{RO} = \frac{1}{3}(0.0625)(3) = 0.0625 \text{ ft}$$

Then use Equation 1-4 to calculate H_{VO},

$$H_{VO} = 12 - 8 + 0.0625 = 4.0625 \text{ ft}$$

Therefore,

$$V_V = \frac{\pi}{4}(6)^2 (4.0625) = 114.86 \text{ ft}^3$$

   b. Vapor density, W_V

$$W_v = \frac{M_V \; P_{VA}}{R \; T_{LA}} \qquad (1\text{-}9)$$

    $R = $ ideal gas constant $= 10.731 \dfrac{\text{psia} \cdot \text{ft}^3}{\text{lb-mole} \cdot {}^\circ R}$

$$M_V = \text{stock vapor molecular weight, lb/lb-mole}$$

$$P_{VA} = \text{stock vapor pressure at the daily average liquid surface temperature, psia}$$

$$T_{LA} = \text{daily average liquid surface temperature, °R}$$

First calculate T_{LA} using Equation 1-13.

$$T_{LA} = 0.44 \ T_{AA} + 0.56 \ T_B + 0.0079 \ \alpha \ I \qquad (1\text{-}13)$$

where:

$$T_{AA} = \text{daily average ambient temperature, °R}$$

$$T_B = \text{liquid bulk temperature, °R}$$

$$I = \text{daily total solar absorptance, Btu/ft·day} = 1{,}568 \text{ (see Table 12.3-6)}$$

$$\alpha = \text{tank paint solar absorptance} = 0.17 \text{ (see Table 12.3-7)}$$

T_{AA} and T_B must be calculated from Equations 1-14 and 1-15.

$$T_{AA} = \frac{T_{AX} + T_{AN}}{2} \qquad (1\text{-}14)$$

from Table 12.3-6, for Denver, Colorado:

$$T_{AX} = \text{daily maximum ambient temperature} = 64.3°F$$

$$T_{AN} = \text{daily minimum ambient temperature} = 36.2°F$$

Converting to °R:

$$T_{AX} = 64.3 + 460 = 524.3°R$$

$$T_{AN} = 36.2 + 460 = 496.2°R$$

Therefore,

$$T_{AA} = (524.3 + 496.2)/2 = 510.25 \ °R$$

$$T_B = \text{liquid bulk temperature} = T_{AA} + 6\alpha - 1 \qquad (1\text{-}15)$$

$$T_{AA} = 510.25 \ °R \text{ from previous calculation}$$

α = paint solar absorptance = 0.17 (see Table 12.3-7)

I = daily total solar insolation on a horizontal surface = 1,568 Btu/ft$^2 \cdot$day (see Table 12.3-6)

Substituting values in Equation 1-15

$$T_B = 510.25 + 6 (0.17) - 1 = 510.27 \text{ °R}$$

Using Equation 1-13,

$$T_{LA} = (0.44)(510.25°R) + 0.56(510.27°R) + 0.0079(0.17)(1,568) = 512.36°R$$

Second, calculate P_{VA} using Raoult's Law.

According to Raoult's Law, the partial pressure of a component is the product of its pure vapor pressure and its liquid mole fraction. The sum of the partial pressures are equal to the total vapor pressure of the component mixture stock.

The pure vapor pressure for benzene, toluene, and cyclohexane can be calculated from Antoine's equation. For benzene, Table 12.3-5 provides the Antoines coefficients which are A = 6.905, B = 1,211.033, and C = 220.79. For toluene, A = 6.954, B = 1,344.8, and C = 219.48. For cyclohexane, A = 6.841, B = 1,201.53, and C = 222.65. Therefore:

$$\log P = A - \frac{B}{T + C}$$

For benzene,

$$\log P = 6.905 - \frac{1,211.033}{(11°C + 220.79)}$$

$$P = 47.90 \text{ mmHg} = 0.926 \text{ psia}$$

Similarly for toluene and cyclohexane,

$$P = 0.255 \text{ psia for toluene}$$

$$P = 0.966 \text{ psia for cyclohexane}$$

In order to calculate the mixture vapor pressure, the partial pressures need to be calculated for each component. The partial pressure is the product of the pure vapor pressure of each component (calculated above) and the mole fractions of each component in the liquid.

The mole fractions of each component are calculated as follows:

	Amount, lb	$\div M_i$	Moles	x_i
Benzene	2,812	78.1	36.0	0.90
Toluene	258	92.1	2.80	0.07
Cyclohexane	101	84.2	1.20	0.03
Total			40.0	1.00

where:

M_i = molecular weight of component

x_i = liquid mole fraction

The partial pressures of the components can then be calculated by multiplying the pure vapor pressure by the liquid mole fraction as follows:

	P at 52°F	x_i	$P_{partial}$
Benzene	0.926	0.90	0.833
Toluene	0.255	0.07	0.018
Cyclohexane	0.966	0.03	0.029
Total		1.0	0.880

The vapor pressure of the mixture is then 0.880 psia.

Third, calculate the molecular weight of the vapor, M_V. Molecular weight of the vapor depends upon the mole fractions of the components in the vapor.

$$M_V = \sum M_i y_i$$

where:

M_i = molecular weight of the component

y_i = vapor mole fraction

The vapor mole fractions, y_i, are equal to the partial pressure of the component divided by the total vapor pressure of the mixture.

Therefore,

$$y_{benzene} = P_{partial}/P_{total} = 0.833/0.880 = 0.947$$

Similarly, for toluene and cyclohexane,

$$y_{toluene} = P_{partial}/P_{total} = 0.020$$

$$y_{cyclohexane} = P_{partial}/P_{total} = 0.033$$

The mole fractions of the vapor components sum to 1.0.

The molecular weight of the vapor can be calculated as follows:

	M_i	y_i	M_v
Benzene	78.1	0.947	74.0
Toluene	92.1	0.020	1.84
Cyclohexane	84.2	0.033	2.78
Total			78.6

Since all variables have now been solved, the stock density, W_V, can be calculated:

$$W_v = \frac{M_V P_{VA}}{R \, T_{LA}}$$

$$\frac{(78.6) \ (0.880)}{(10.731) \ (512.36)} = 1.26 \times 10^{-2} \ \frac{lb}{ft^3}$$

c. K_E, vapor space expansion factor can be calculated using the following equation:

$$K_E = \frac{\Delta T_V}{T_{LA}} + \frac{\Delta P_V - \Delta P_B}{P_A - P_{VA}} \qquad (1\text{-}16)$$

where:

ΔT_V = daily vapor temperature range, °R

ΔP_V = daily vapor pressure range, °R

ΔP_B = breather vent pressure setting range, psia

P_A = atmospheric pressure, 14.7 psia (given)

P_{VA} = vapor pressure at daily average liquid surface temperature, psia = 0.881 psia (from Step 4b)

T_{LA} = daily average liquid surface temperature, °R = 512.36°R (from Step 4b)

First, calculate the daily vapor temperature range from Equation 1-17,

$$\Delta T_V = 0.72 \Delta T_A + 0.028\alpha I \qquad (1\text{-}17)$$

where:

ΔT_V = daily vapor temperature range, °R

ΔT_A = daily ambient temperature range = $T_{AX} - T_{AN}$

α = tank paint solar absorptance, 0.17 (given)

I = daily total solar insolation, 1,568 Btu/ft^3·day (given)

from Table 12.3-6, for Denver, Colorado:

T_{AX} = 64.3°F

T_{AN} = 36.2°F

Converting to °R,

T_{AX} = 64.3 + 460 = 524.3°R

T_{AN} = 36.2 + 460 = 496.2°R

From equation 1-17,

ΔT_A = 524.3 - 496.2 = 28.1°R

Therefore,

ΔT_V = 0.72 (28.1) + (0.028)(0.17)(1568) = 27.7°R

Second, calculate the daily vapor pressure range using Equation 1-18,

$$\Delta P_V = P_{VX} - P_{VN} \qquad (1\text{-}18)$$

$P_{VX/VN}$ = vapor pressure at the daily maximum/minimum liquid temperature can be calculated in a manner similar to the P_{VA} calculation shown earlier.

T_{LX} = maximum liquid temperature, T_{LA} + 0.25 ΔT_V (from Figure 12.3-5)

T_{LN} = minimum liquid temperature, T_{LA} - 0.25 ΔT_V (from Figure 12.3-5)

T_{LA} = 512.36 (from Step 4b)

ΔT_V = 27.7°R

T_{LX} = 512.36 + (0.25) (27.7) = 519.3°R or 59°F

T_{LN} = 512.36 - (0.25) (27.7) = 505.4°R or 45°F

Using Antoine's equation, the pure vapor pressures of each component at the minimum liquid surface temperature are:

$P_{benzene}$ = 0.758 psia

$P_{toluene}$ = 0.203 psia

$P_{cyclohexane}$ = 0.794 psia

The partial pressures for each component at T_{LN} can then be calculated as follows:

	P at 45°F	x_i	$P_{partial}$
Benzene	0.758	0.90	0.68
Toluene	0.203	0.07	0.01
Cyclohexane	0.794	0.03	0.02
Total		1.0	0.71

Using Antoines equation, the pure vapor pressure of each component at the maximum liquid surface temperature are:

$P_{benzene}$ = 1.14 psia

$P_{toluene}$ = 0.32 psia

$P_{cyclohexane}$ = 1.18 psia

The partial pressures for each component at T_{LX} can then be calculated as follows:

	P	x_i	$P_{partial}$
Benzene	1.14	0.90	1.03
Toluene	0.32	0.07	0.02
Cyclohexane	1.18	0.03	0.04
Total		1.0	1.09

Therefore, the vapor pressure range, $\Delta P_v = P_{LX} - P_{LN} = 1.09 - 0.710 = 0.38$ psia.
Next, calculate the breather vent pressure, ΔP_B, from equation 1-20

$$\Delta P_B = P_{BP} - P_{BV} \qquad (1\text{-}20)$$

where:

P_{BP} = breather vent pressure setting = 0.03 psia (given) (see Note 3 to Equation 1-16)

P_{BV} = breather vent vacuum setting = -0.03 psig (given) (see Note 3 to Equation 1-16)

$\Delta P_B = 0.03 - (-0.03) = 0.06$ psig

Finally, K_B, can be calculated by substituting values into Equation 1-16.

$$K_B = \frac{(27.7)}{(512.36)} + \frac{0.38 - 0.06 \text{ psia}}{14.7 \text{ psia} - 0.880 \text{ psia}} = 0.077$$

d. The vented vapor space saturation factor, K_s, can be calculated from Equation 1-22.

$$K_S = \frac{1}{1 + 0.053 \, P_{VA} \, H_{VO}} \qquad (1\text{-}22)$$

where:

P_{VA} = 0.880 psia (from Step 4b)

H_{VO} = 4.0625 ft (from Step 4a)

$$= \frac{1}{1 + 0.053(0.880)(4.0625)} = 0.841$$

5. Calculate standing storage losses.

$$L_S = 365 \, W_V V_V K_E K_S$$

Using the values calculated above:

$W_V = 1.26 \times 10^{-2} \, \dfrac{lb}{ft^3}$ (from Step 4b)

$V_V = 114.86 \, ft^3$ (from Step 4a)

$K_E = 0.077$ (from Step 4c)

$K_S = 0.841$ (from Step 4d)

$L_S = 365 \, (1.26 \times 10^{-2})(114.86)(0.077)(0.841) = 34.2 \, lb/yr$

6. Calculate working losses.

The amount of VOC's emitted as a result of filling operations can be calculated from the following equation:

$$L_W = (0.0010) \, (M_V)(P_{VA})(Q)(K_N)(K_P) \tag{1-23}$$

From Step 4:

$M_V = 78.6$ (from Step 4b)

$P_{VA} = 0.880 \, psia$ (from Step 4b)

$Q = 8{,}450 \, gal/yr \times 2.381 \, bbl/100 \, gal = 201 \, bbl/yr$ (given)

$K_P =$ product factor, dimensionless $= 1$ for volatile organic liquids, 0.75 for crude oils

$K_N = 1$ for turnovers ≤ 36 (given)

$N =$ turnovers per year $= 5$ (given)

$L_W = (0.0010)(78.6)(0.880)(201)(1)(1) = 13.9 \, lb/yr$

7. Calculate total losses, L_T.

$$L_T = L_S + L_W$$

where:

L_S = 34.2 lb/yr

L_W = 13.9 lb/yr

L_T = 34.7 + 13.9 = 48.1 lb/yr

8. Calculate the amount of each component emitted from the tank.

The amount of each component emitted is equal to the weight fraction of the component in the vapor times the amount of total VOC emitted. Assuming 100 moles of vapor are present, the number of moles of each component will be equal to the mole fraction multiplied by 100. This assumption is valid regardless of the actual number of moles present. Therefore,

Component	No. of moles x	M_i =	Pounds$_i$	Weight fraction
Benzene	94.7	78.1	7,396	0.94
Toluene	2.0	92.1	184	0.02
Cyclohexane	3.3	84.3	278	0.04
Total	100		7,858	1.0

$$\text{Weight fraction} = \frac{\text{pounds}_i}{\text{total pounds}}$$

Amount of each component emitted is then calculated by:

Component	Weight fraction x	Total VOC emitted =	Pounds$_i$ emitted
Benzene	0.94	48.1	45.2
Toluene	0.02	48.1	0.96
Cyclohexane	0.04	48.1	1.92
Total			48.1

Example 2 - Chemical Mixture in a Horizontal Tank - Assuming that the tank mentioned in Example 1 is now horizontal, calculate emissions. (Tank diameter - 6 ft and length - 12ft.)

Solution

Emissions from horizontal tanks can be calculated by adjusting parameters in the fixed roof equations. Specifically, an effective diameter, D_E, is used in place of the tank diameter, D. The vapor space height, H_{VO}, is assumed to be half the actual tank diameter.

1. Horizontal tank adjustments. Make adjustments to horizontal tank values so that fixed roof tank equations can be used. The effective diameter, D_E, is calculated as follows:

$$D_B = \sqrt{\frac{DL}{0.785}}$$

$$D_B = \sqrt{\frac{(6)(12)}{0.785}} = 9.577 \text{ ft.}$$

The vapor space height, H_{VO} is calculated as follows:

$$H_{VO} = 1/2\ D = 1/2\ (6) = 3 \text{ ft}$$

2. Given the above adjustments the standing storage loss, L_S, can be calculated.

Calculate values for each effected variable on the standing loss equation.

$$L_S = 365\ (V_V)\ (W_V)\ (K_E)\ (K_S)$$

V_V and K_S depend on the effective tank diameter, D_E, and vapor space height, H_{VO}.

These variables can be calculated using the values derived in Step 1:

$$V_V = \frac{\pi}{4} (D_E)^2 H_{VO}$$

$$V_V = \frac{\pi}{4} (9.577)^2 (3) = 216.10 \text{ ft}^3$$

$$K_S = \frac{1}{1 + (0.053)(P_{VA})(H_{VO})}$$

$$K_S = \frac{1}{1 + (0.053)(0.880)(3)} = 0.877$$

3. Calculate standing storage loss using the values calculated in Step 2.

$$L_S = 365 (V_V)(W_V)(K_E)(K_S)$$

$$V_V = 216.10 \text{ ft}^3 \text{ (from Step 2)}$$

$$W_V = 1.26 \times 10^{-2} \text{ lb/ft}^3 \text{ (from Step 4b)}$$

$$K_E = 0.077 \text{ (from Step 4c)}$$

$$K_S = 0.877 \text{ (from Step 2)}$$

$$L_S = (365)(1.26 \times 10^{-2})(216.10)(0.077)(0.877)$$

$$L_S = 67.1 \text{ lb/yr}$$

4. Calculate working loss. Since the parameters for working loss do not depend on diameter or vapor space height, the working loss for a horizontal tank of the same capacity as the tank in Example 1 will emit the same amount as working loss.

$$L_W = 13.9 \text{ lb/yr}$$

5. Calculate total emissions.

$$L_T = L_S + L_W$$

$$L_T = 67.1 + 13.9 = 81 \text{ lb/yr}$$

Example 3 - Chemical Mixture in an External Floating Roof Tank - Determine the yearly emission rate of a mixture that is 75 percent benzene, 15 percent toluene, and 10 percent cyclohexane, by weight, from a 100,000-gallon external floating roof tank with a pontoon roof. The tank is 20 feet in diameter. The tank has 10 turnovers per year. The tank has a mechanical shoe seal (primary seal) and a shoe-mounted secondary seal. The tank is made of welded steel and has a light rust covering the inside surface of the shell. The tank shell is painted white, and the tank is located in Newark, New Jersey. The floating roof is equipped with the following fittings: (1) an ungasketed access hatch with an unbolted cover, (2) an unspecified number of ungasketed vacuum breakers with weighted mechanical actuation, and (3) ungasketed gauge hatch/sample wells with weighted mechanical actuation.

Solution:

1. Determine tank type. The tank is an external floating roof storage tank.

2. Determine estimating methodology. The product consists of three organic liquids, all of which are miscible in each other, which make a homogenous mixture if the material is well mixed. The tank emission rate will be based upon the properties of the mixture. Because the components have similar structures and molecular weights, Raoult's Law is assumed to apply to the mixture.

3. Select equations to be used. For an external floating roof tank,

$$L_T = L_{WD} + L_R + L_F \qquad (2\text{-}1)$$

$$L_{WD} = (0.943) QCW_L/D \qquad (2\text{-}4)$$

$$L_R = K_R v^n P^* D M_V K_C \qquad (2\text{-}2)$$

$$L_F = F_F P^* M_V K_C \qquad (2\text{-}5)$$

where:

L_T = total loss, lb/yr

L_{WD} = withdrawal loss, lb/yr

L_R = rim seal loss from external floating roof tanks, lb/yr

L_F = roof fitting loss, lb/yr

Q = product average throughput, bbl/yr

C = product withdrawal shell clingage factor, bbl/1,000 ft^2; see Table 12.3-10

W_L = density of product, lb/gal

D = tank diameter, ft

K_R = seal factor, lb-mole/[ft(mph)$^n \cdot$ ft $\cdot$ yr)]

v = average windspeed for the tank site, mph

n = seal windspeed exponent, dimensionless

P^* = the vapor pressure function, dimensionless

$P^* = (P_{VA}/P_A)/(1 + [1-(P_{VA}/P_A)]^{0.5})^2$

where:

P_{VA} = the true vapor pressure of the materials stored, psia

P_A = atmospheric pressure, psia = 14.7

M_V = molecular weight of product vapor, lb/lb-mol

K_C = product factor, dimensionless

F_F = the total deck fitting loss factor, lb-mol/yr

$$= \sum_{i}^{n_f} = 1(N_{F_i}K_{F_i}) = [(N_{F_1}K_{F_1}) + (N_{F_2}K_{F_2}) + ... + N_{F_{n_f}}K_{F_{n_f}})] \qquad (2\text{-}6)$$

where:

N_{F_i} = number of fittings of a particular type, dimensionless. N_{F_i} is determined for the specific tank or estimated from Tables 12.3-11, 12.3-12, or 12.3-13

K_{F_i} = roof fitting loss factor for a particular type of fitting, lb-mol/yr. K_{F_i} is determined for each fitting type from Table 12.3-11.

n_f = number of different types of fittings, dimensionless = 3

4. Identify parameters to be calculated/determined from tables. In this example, the following parameters are not specified: W_L, F_F, C, K_R, v, n, P_{VA}, P^*, M_V, and K_C. Some typical assumptions that can be made are as follows:

v = average windspeed for the tank site = 10.2 mph (see Table 12.3-9)

K_C = 1.0 for volatile organic liquids

$C = 0.0015$ bbl/1,000 ft^2 for tanks with light rust (from Table 12.3-10)

$K_R = 0.8$ (from Table 12.3-8)

$n = 1.2$ (from Table 12.3-8)

F_F, W_L, P_{VA}, P^*, and M_V still need to be calculated.

F_F is estimated by calculating the individual K_{F_i} and N_{F_i} for each of the three types of roof fittings used in this example. For the ungasketed access hatches with unbolted covers, the K_f value can be calculated using information in Table 12.3-11. For this fitting, $K_{fa} = 2.7$, $K_{fb} = 7.1$, and $m = 1$. There is normally one access hatch. So,

$$K_{f_{acess\ hatch}} = K_{fa} + K_{fb}v^m$$

$$= 2.7 + (7.1)(10.2)^1$$

$$= 75.1\ \text{lb-mol/yr}$$

$$K_{f_{access\ batch}} = 75.1\ \text{lb-mol/yr}$$

$$N_{f_{access\ hatch}} = 1$$

The number of vacuum breakers can be taken from Table 12.3-12. For tanks with a diameter of 20 feet and a pontoon roof, the number of vacuum breakers is one.
Table 12.3-11 provides fitting factors for weighted mechanical action, ungasketed vacuum breakers when the average windspeed is 10.2 mph. Based on this table, $K_{fa} = 1.1$, $K_{fb} = 3.0$, and $m = 1$. So,

$$K_{F_{vacuum\ breaker}} = K_{FA} + K_{FB}(v^m)$$

$$K_{F_{vacuum\ breaker}} = 1.1 + 3.0\ (10.2)^1$$

$$K_{F_{vacuum\ breaker}} = 31.7\ \text{lb-mol/yr}$$

$$N_{F_{vacuum\ breaker}} = 1$$

For the ungasketed gauge hatch/sample wells with weighted mechanical actuation, Table 12.3-11 indicates that tanks normally have only one. This table also indicates that $K_{fa} = 0.91$, $K_{fb} = 2.4$, and $m = 1$. Therefore,

$$K_{F_{gauge\ hatch/sample\ well}} = K_{FA} + K_{FB}(v^m)$$

$$K_F = 0.91 + 2.4 \ (10.2)^1$$

$$K_{F\text{gauge hatch/sample well}} = 25.4 \text{ lb-mol/yr}$$

$$N_{F\text{gauge hatch/sample well}} = 1$$

F_F can be calculated from Equation 2-6:

$$= \sum_{i=1}^{3} (K_{F_i})(N_{F_i})$$

$$= (75.1)(1)+(31.7)(1)+(25.4)(1)$$

$$= 132.2 \text{ lb-mol/yr}$$

5. <u>Calculate mole fractions in the liquid</u>. The mole fractions of components in the liquid must be calculated in order to estimate the vapor pressure of the liquid using Raoult's Law. For this example, the weight fractions (given as 75 percent benzene, 15 percent toluene, and 10 percent cyclohexane) of the mixture must be converted to mole fractions. First, assume that there are 1,000 lb of liquid mixture. Using this assumption, the mole fractions calculated will be valid no matter how many pounds of liquid actually are present. The amount (pounds) of each component is equal to the weight fraction times 1,000:

Component	Weight fraction x 1,000 lb	= Pounds	M_i. lb/ ÷ lb-moles	= Moles	Mole fraction
Benzene	0.75	750	78.1	9.603	0.773
Toluene	0.15	150	92.1	1.629	0.131
Cyclohexane	0.10	100	84.2	1.188	0.096
Total	1.00	1,000		12.420	1.000

For example, the mole fraction of benzene in the liquid is 9.603/12.420 = 0.773.

6. <u>Determine the daily average liquid surface temperature</u>. The daily average liquid surface temperature is equal to:

$$T_{LA} = 0.44 \ T_{AA} + 0.56 \ T_B + 0.0079 \ \alpha \ I$$

$$T_{AA} = (T_{AX} + T_{AN})/2$$

$$T_B = T_{AA} + 6\alpha - 1$$

For Newark, New Jersey (see Table 12.3-6):

T_{AX} = 62.5°F = 522.2°R

T_{AN} = 45.9°F = 505.6°R

I = 1,165 Btu/ft^2•d

From Table 12.3-7, α = 0.17

Therefore;

T_{AA} = (522.2 + 505.6)/2 = 513.9°R

T_B = 513.9°R + 6 (0.17) - 1 = 513.92°R

T_{LA} = 0.44 (513.9) + 0.56 (513.92) + 0.0079 (0.17)(1,165)

T_{LA} = 226.12 + 287.8 + 1.56 = 515.5°R

$$T_{LA} = 55.8°F = 56°F$$

7. <u>Calculate partial pressures and total vapor pressure of the liquid</u>. The vapor pressure of each component at 56°F can be determined using Antoines equation. Since Raoult's Law is assumed to apply in this example, the partial pressure of each component is the liquid mole fraction (x_i) times the vapor pressure of the component (P).

Component	P at 56°F	x_i	$P_{partial}$
Benzene	1.04	0.773	0.80
Toluene	0.29	0.131	0.038
Cyclohexane	1.08	0.096	0.104
Totals		1.00	0.942

The vapor pressure of the mixture is estimated to be 0.942 psia.

8. <u>Calculate mole fractions in the vapor</u>. The mole fractions of the vapor phase are based upon the partial pressure that each component exerts (calculated in Step 7).

The total vapor pressure of the mixture is 0.942 psia. So for benzene:

$y_{benzene}$ = $P_{partial}/P_{total}$ = 0.80/0.942 = 0.85

where:

$y_{benzene}$ = mole fraction of benzene in the vapor

$P_{partial}$ = partial pressure of benzene in the vapor, psia

$$P_{total} = \text{total vapor pressure of the mixture, psia}$$

Similarly,

$$y_{toluene} = 0.038/0.942 = 0.040$$

$$y_{cyclohexane} = 0.104/0.942 = 0.110$$

The vapor phase mole fractions sum to 1.0.

9. <u>Calculate molecular weight of the vapor</u>. The molecular weight of the vapor depends upon the mole fractions of the components in the vapor.

$$M_V = \Sigma M_i y_i$$

where:

M_v = molecular weight of the vapor
M_i = molecular weight of the component
y_i = mole fraction of component in the vapor

Component	M_i	y_i	$M_V = \Sigma(M_i)(y_i)$
Benzene	78.1	0.85	66.39
Toluene	92.1	0.040	3.68
Cyclohexane	84.2	0.110	9.26
Total		1.00	79.3

The molecular weight of the vapor is 79.3 lb/lb-mol.

10. <u>Calculate weight fractions of the vapor</u>. The weight fractions of the vapor are needed to calculate the amount (in pounds) of each component emitted from the tank. The weight fractions are related to the mole fractions calculated in Step 7.

$$Z_{i,v} = \frac{y_i M_i}{M_v}$$

$$Z_{i,v} = \frac{(0.85)(78.1)}{79.3} = 0.84 \text{ for benzene}$$

$$Z_{i,v} = \frac{(0.040)(92.1)}{79.3} = 0.04 \text{ for toluene}$$

$$Z_{i,v} = \frac{(0.110)(84.2)}{79.3} = 0.12 \text{ for cyclohexane}$$

11. Calculate total VOC emitted from the tank. The total VOC emitted from the tank is calculated using the equations identified in Step 3 and the parameters calculated in Steps 4 through 9.

$$L_T = L_{WD} + L_R + L_F$$

$$L_{WD} = 0.943 \; QCW_L/D$$

where:

$Q = $ 100,000 gal x 10 turnovers/yr (given)

$= $ 1,000,000 gal x 2.381 bbl/100 gal = 23,810 bbl/yr

$C = $ 0.0015 bbl/10^3 ft^2 (from Table 12.3-10)

$W_L = $ 1/[Σ (wt fraction in liquid)/(liquid density from Table 12.3-3)]

Weight fractions

Benzene = 0.75 (given)
Toluene = 0.15 (given)
Cyclohexane = 0.10 (given)

Liquid densities

Benzene = 7.4 (see Table 12.3-3)
Toluene = 7.3 (see Table 12.3-3)
Cyclohexane = 6.5 (see Table 12.3-3)

$W_L = $ 1/[(0.75/7.4) + (0.15/7.3) + (0.10/6.5)]

$= $ 1/(0.101 + 0.0205 + 0.0154)

$= $ 1/0.1369

$= $ 7.3 lb/gal

$D = $ 20 ft (given)

$L_{WD} = 0.943 \; QCW_L/D$

$= $ [0.943(23,810)(0.0015)(7.3)/20]

$= $ 12.3 lb of VOC/yr

$$L_R = K_R v^n P^* D M_V K_C$$

where:

K_R = 0.8 (from Step 4)

v = 10.2 mph (from Step 4)

n = 1.2 (from Step 4)

P_{VA} = 0.942 psia (from Step 7)

$P^* = (0.942/14.7)/(1+[1-(0.942/14.7)]^{0.5})^2$ (formula from Step 3)

P^* = 0.017

M_V = 79.3 lb/lb-mol (from Step 9)

$L_R = (0.8)(10.2)^{1.2}(0.017)(20)(79.3)(1.0)$

= 350 lb of VOC/yr

$$L_F = F_F P^* M_V K_C$$

where:

F_F = 132.2 lb-mol/yr (from Step 4)

P^* = 0.017

M_V = 79.3 lb/lb-mol

K_C = 1.0 (from Step 4)

$L_F = (132.2)(0.017)(79.3)(1.0)$

= 178 lb/yr of VOC emitted

$L_T = L_{WD} + L_R + L_F$

= 12.3 + 350 + 178

= 540 lb/yr of VOC emitted from tank

12. <u>Calculate amount of each component emitted from the tank</u>. For an external floating roof tank, the individual component losses are equal to:

$$L_{T_i} = (Z_{i,v})(L_R + L_F) + (Z_{i,L})(L_{WD})$$

Therefore,

L_T = (0.84)(528) + (0.75)(12.3) = 453 lb/yr benzene

L_T = (0.040)(528) + (0.15)(12.3) = 23 lb/yr toluene

$$L_T = (0.12)(528) + (0.10)(12.3) = 65 \text{ lb/yr cyclohexane}$$

Example 4 - Gasoline in an Internal Floating Roof Tank - Determine emissions of product from a 1 million gallon, internal floating roof tank containing gasoline (RVP 13). The tank is painted white and is located in Tulsa, Oklahoma. The annual number of turnovers for the tank is 50. The tank is 70 ft in diameter and 35 ft high and is equipped with a liquid-mounted primary seal plus a secondary seal. The tank has a column-supported fixed roof. The tank's deck is welded and equipped with the following: (1) two access hatches with an unbolted, ungasketed cover; (2) an automatic gauge float well with an unbolted, ungasketed cover; (3) a pipe column well with a flexible fabric sleeve seal; (4) a sliding cover, gasketed ladder well; (5) fixed roof legs; (6) a slotted sample pipe well with a gasketed sliding cover; and (7) a weighted, gasketed vacuum breaker.

Solution:

1. Determine tank type. The following information must be known about the tank in order to use the internal floating roof equations:

    --the number of columns
    --the effective column diameter
    --the system seal description (vapor- or liquid-mounted, primary or secondary seal)
    --the deck fitting types and the deck seam length

    Some of this information depends on specific construction details, which may not be known. In these instances, approximate values are provided for use.

2. Determine estimating methodology. Gasoline consists of many organic compounds, all of which are miscible in each other, which form a homogenous mixture. The tank emission rate will be based on the properties of RVP 13 gasoline. Since vapor pressure data have already been compiled, Raoult's Law will not be used. The molecular weight of gasoline also will be taken from a table and will not be calculated. Weight fractions of components will be assumed to be available from SPECIATE database.

3. Select equations to be used.

$$L_T = L_{WD} + L_R + L_F + L_D \tag{3-1}$$

$$L_{WD} = \frac{(0.943) \, QCW_L}{D} \left[1 + \left(\frac{NcFc}{D}\right)\right] \tag{3-4}$$

$$L_R = K_R P^* D M_v K_c \tag{3-2}$$

$$L_F = F_F P^* M_v K_C \tag{3-5}$$

$$L_D = K_D S_D D^2 P^* M_v K_C \tag{3-6}$$

where:

$$L_T = \text{total loss, lb/yr}$$

$$L_{WD} = \text{withdrawal loss, lb/yr}$$

$$L_R = \text{rim seal loss, lb/yr}$$

$$L_F = \text{deck fitting loss, lb/yr}$$

$$L_D = \text{deck seam loss, lb/yr}$$

For this example:

Q = product average throughput, bbl/yr [tank capacity (bbl/turnover) X turnovers/yr]

C = product withdrawal shell clingage factor, bbl/1,000 ft^2

W_L = density of liquid, lb/gal

D = tank diameter, ft

N_C = number of columns, dimensionless

F_C = effective column diameter, ft

K_R = seal factor, lb-mole/ft·yr

M_V = the average molecular weight of the product vapor, lb/lb-mol

K_C = the product factor, dimensionless

P^* = the vapor pressure function, dimensionless

$= (P_{VA}/P_A)/[1 + (1-([P_{VA}/P_A]))^{0.5})]^2$

where:

P_{VA} = the vapor pressure of the material stored, psia

P_A = average atmospheric pressure at tank location, psia

F_F = the total deck fitting loss factor, lb-mol/yr

$$= \sum_{i=1}^{n_f} (N_{F_i} K_{F_i}) = [(N_{F_1} K_{F_1}) + (N_{F_2} K_{F_2}) + \dots + (N_{F_{n_f}} K_{F_{n_f}})]$$

where:

N_{F_i} = number of fittings of a particular type, dimensionless. N_{F_i} is determined for the specific tank or estimated from Table 12.3-16

K_{F_i} = deck fitting loss factor for a particular type of fitting, lb-mol/yr. K_{F_i} is determined for each fitting type from Table 12.3-16

n_f = number different types of fittings, dimensionless

K_D = the deck seam loss factor, lb-mol/ft•yr

= 0.34 for nonwelded roofs

= 0 for welded decks

S_D = deck seam length factor, ft/ft^2

= L_{seam}/A_{deck}

where:

L_{seam} = total length of deck seams, ft

A_{deck} = area of deck, ft^2 = $\pi D^2/4$

4. Identify parameters to be calculated or determined from tables. In this example, the following parameters are not specified: N_C, F_C, P, M_V, K_S, P^*, K_C, F_F, K_D, and S_D. The density of the liquid (W_L) and the vapor pressure of the liquid (P) can be read from tables and do not need to be calculated. Also, the weight fractions of components in the vapor can be obtained from speciation manuals. Therefore, several steps required in preceding examples will not be required in this example. In each case, if a step is not required, the reason is presented.

The following parameters can be obtained from tables or assumptions:

K_C = 1.0 (for volatile organic liquids)

N_C = 1 (from Table 12.3-15)

F_C = 1.0 (assumed)

K_R = 1.6 (from Table 12.3-14)

M_V = 62 lb/lb-mol (from Table 12.3-2)

W_L = 4.9 lb/gal (from Table 12.3-2)

C = 0.0015 bbl/1,000 ft^2 (from Table 12.3-10)

K_D = 0 (for welded roofs)

S_D = 0.2 ft/ft^2 (from Table 12.3-17)

F_F = values taken from Table 12.3-18

$\quad$ = $\Sigma \, (K_{F_i} N_{f_i})$

$\quad$ = $(25)(2) + (28)(1) + (10)(1) + (56)(1) + 0\,[5 + (70/10) + (70^2/600)] +$
$\quad\quad (44)(1) + (0.7)(1)$

$\quad$ = 188.7 lb-mol/yr

5. <u>Calculate mole fractions in the liquid</u>. This step is not required because liquid mole fractions are only used to calculate liquid vapor pressure, which is given in this example.

6. <u>Calculate the daily average liquid surface temperature</u>. The daily average liquid surface temperature is equal to:

T_{LA} = $0.44 \, T_{AA} + 0.56 \, T_B + 0.0079 \, \alpha \, I$

T_{AA} = $(T_{AX} + T_{AN})/2$

T_B = $T_{AA} + 6\alpha - 1$

For Tulsa, Oklahoma (see Table 12.3-6):

T_{AX} = $71.3°F = 530.97°R$

T_{AN} = $49.2°F = 508.87°R$

I = $1{,}373 \; Btu/ft^2 \bullet day$

From Table 12.3-7, α = 0.17

Therefore,

T_{AA} = $(530.97 + 508.87)/2 = 519.92°R$

T_B = $519.92 + 6(0.17) - 1 = 519.94°R$

T_{LA} = $0.44\,(519.92) + 0.56\,(519.94) + 0.0079(0.17)(1{,}373)$

T_{LA} = $228.76 + 291.17 + 1.84$

T_{LA} = 521.77 or $62°F$

7. <u>Calculate partial pressures and total vapor pressure of the liquid</u>. The vapor pressure of gasoline RVP 13 can be interpolated from Table 12.3-2. The interpolated vapor pressure at 62°F is equal to 7.18 psia. Therefore,

$$P^* = (7.18/14.7)/[1 + (1-(7.18/14.7))^{0.5}]^2$$

$$P^* = 0.166$$

8. **Calculate mole fractions in the vapor.** This step is not required because vapor mole fractions are needed to calculate the weight fractions and the molecular weight of the vapor, which are already specified.

9. **Calculate molecular weight of the vapor.** This step is not required because the molecular weight of gasoline vapor is already specified.

10. **Calculate weight fractions of the vapor.** The weight fractions of gasoline vapor can be obtained from a VOC speciation manual.

11. **Calculate total VOC emitted from the tank.** The total VOC emitted from the tank is calculated using the equations identified in Step 3 and the parameters specified in Step 4.

$$L_T = L_{WD} + L_R + L_F + L_D$$

$$L_{WD} = [(0.943)QCW_L]/D \times [1 + (N_CF_C)/D]$$

where:

Q = (1,000,000 gal) X (50 turnovers/yr)

    = (50,000,000 gal) X (2.381 bbl/100 gal) = 1,190,500 bbl/yr

C = 0.0015 bbl/1,000 ft^2

W_L = 4.9 lb/gal

D = 70 ft

N_C = 1

F_C = 1

L_{WD} = [(0.943)(1,190,500)(0.0015)(4.9)]/70 X [1 + (1)(1)/70] = 119.6 lb/yr

$$L_R = K_RDP^*M_VK_C$$

where:

K_R = 1.6 lb-mole/ft·yr

P^* = 0.166

D = 70 ft

M_V = 62 lb/lb-mol

K_C = 1.0

L_R = (1.6)(0.166)(70)(62)(1.0) = 1,153 lb/yr of VOC emitted

$$L_F = F_F P^* M_V K_C$$

where:

$$F_F = 188.7 \text{ lb-mol/yr}$$

$$P^* = 0.166$$

$$M_V = 62 \text{ lb/lb-mol}$$

$$K_C = 1$$

$$L_F = (188.7)(0.166)(62)(1.0) = 1,942 \text{ lb/yr of VOC emitted}$$

$$L_D = K_D S_D D^2 P^* M_V K_C$$

where:

$$K_D = 0$$

$$S_D = 0.2$$

$$D = 70 \text{ ft}$$

$$P^* = 0.166$$

$$M_V = 62 \text{ lb/lb-mol}$$

$$K_C = 1.0$$

$$L_D = (0.0)(0.2)(70)^2(0.166)(62)(1.0) = 0 \text{ lb/yr of VOC}$$

$$L_T = L_{WD} + L_R + L_F + L_D$$

$$= 119.6 + 1,153 + 1,942 + 0 = 3,215 \text{ lb/yr of VOC emitted from the tank}$$

12. Calculate amount of each component emitted from the tank. The individual component losses are equal to:

$$L_{T,i} = (Z_{i,v})(L_R + L_F + L_D) + (Z_{i,L})(L_{WD})$$

Since the liquid weight fractions are unknown, the individual component losses are calculated based on the vapor weight fraction and the total losses. This procedure should yield approximately the same values as the above equation because withdrawal losses are typically low for floating roof tanks. The amount of each component emitted is the weight fraction of that component in the vapor (obtained from a VOC species data manual and shown in Table 12.5-1) times the total amount of VOC emitted from the tank. Table 12.5-1 shows the amount emitted for each component in this example.

TABLE 12.5-1. EMISSIONS FOR EXAMPLE 4

Constituent	Weight percent in vapor x 3,215 lb/yr	= Pounds emitted/yr
Air toxics		
Benzene	0.77	24.8
Toluene	0.66	21.2
Ethylbenzene	0.04	1.29
O-xylene	0.05	1.61
Nontoxics		
Isomers of pentane	26.78	861
N-butane	22.95	738
Iso-butane	9.83	316
N-pentane	8.56	275
Isomers of hexane	4.78	154
3-methyl pentane	2.34	75.2
Hexane	1.84	59.2
Others	21.40	688
Total	100	3,215

EMISSION FACTORS

References for Chapter 12

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15. SUPPLEMENTARY NOTES

16. ABSTRACT

In this Supplement to the Fourth Edition of AP-42 Volume I, new or revised emissions data are presented for Anthracite Coal Combustion; Natural Gas Combustion; Liquified Petroleum Gas Combustion; Wood Waste Combustion In Boilers; Bagasse Combustion In Sugar Mills; Residential Fireplaces; Residential Wood Stoves; Waste Oil Combustion; Automobile Body Incineration; Conical Burners; Open Burning; Stationary Gas Turbines For Electricity Generation; Heavy Duty Natural Gas Fired Pipeline Compressor Engines; Gasoline And Diesel Industrial Engines; Large Stationary Diesel And All Stationary Dual Fuel Engines; Soap And Detergents; and Storage Of Organic Liquids.

17. KEY WORDS AND DOCUMENT ANALYSIS

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